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February 24, 2009

The Honorable Chairman and Members of the
Hawaii Public Utilities Commission
Kekuanaoa Building, 1st Floor
465 South King Street
Honolulu, Hawaii 96813

Dear Commissioners:

Subject: Docket No. 2008-0274 – Decoupling Proceeding
The HECO Companies' Revenue Decoupling Proposal

On January 30, 2009, the Hawaiian Electric Companies[1] filed their Revenue Decoupling Proposal which included information that the Companies designated as confidential and provided subject to the Protective Order approved on January 6, 2009 in this proceeding. Since that time, the Companies have determined that certain of those pages do not contain confidential information and hereby re-submit those pages on a non-confidential basis. Enclosed are the following non-confidential pages:

- Attachment 1: "Revenue Decoupling for Hawaiian Electric Companies;"[2]
- Attachment 5A: "Hawaiian Electric Company, Inc., Decoupling – Proposal (O&M Only – No Change in rate base);
- Attachment 5B, page 4;
- Attachment 5C, page 4;
- Attachment 8A, pages 3, 5-11;
- Attachment 8B, page 4;
- Attachment 8C, page 4;
- Attachment 10A: "Hawaiian Electric Company, Inc., Decoupling – Proposal (No Change to O&M – Regression Analysis Results Applied to Rate Base);
- Attachment 10B, page 4;
- Attachment 10C, page 4;

[1] The "Hawaiian Electric Companies" or "Companies" are Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., and Maui Electric Company, Limited.

[2] The revised version of confidential Attachment 1, which included certain non-substantive corrections, was filed on February 3, 2009.

- Attachment 15.A.1: "Hawaiian Electric Company, Inc., Decoupling – Proposal (Significant Projects Methodology – Average Rate Base);
- Attachment 15.A.2: "Hawaiian Electric Company, Inc., Decoupling – Proposal (Significant Projects Methodology – Full Cost of Project in Rate Base);
- Attachment 15.B.1, page 4;
- Attachment 15.C.1, page 4.

The Companies are also providing non-confidential electronic files for Attachments 1, 5A, 10A, 15.A.1, and 15.A.2. The Company earlier provided electronic files of Excel worksheets that contain both confidential and non-confidential information. Because it is not reasonably practicable to separate the confidential and non-confidential information in an Excel worksheet into separate electronic files, the Companies have designated the entire electronic files as confidential in accordance with paragraph 8 of the Protective Order. This is reasonable, particularly since the Companies have limited their designation of confidential information in the hard copies of those worksheets.

The HECO Companies apologize for any inconvenience this may have caused.

Very truly yours,

Dean K. Matsuura
Manager, Regulatory Affairs

Enclosures

cc: Division of Consumer Advocacy
Hawaii Renewable Energy Alliance
Haiku Design and Analysis
Hawaii Holdings, LLC dba First Wind Hawaii
Department of Business, Economic Development, and Tourism
Hawaii Solar Energy Association
Blue Planet Foundation

Revenue Decoupling for Hawaiian Electric Companies

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1. Introduction

Hawaiian Electric Company Inc. ("HECO") and its sister companies, Hawaiian Electric Light Company Inc. ("HELCO") and Maui Electric Company Inc. ("MECO"), recently reached a comprehensive agreement with the State of Hawaii Division of the Consumer Advocacy of the Department of Commerce and Consumer Affairs ("Consumer Advocate") and other state entities to redouble their efforts to promote energy efficiency and reliance on indigenously produced renewable energy[1]. The agreement, which is an outcome of the Hawaii Clean Energy Initiative ("HCEI"), includes the following key commitments by the HECO companies:

- Accelerate reliance on power purchased from wind and other renewable energy resources
- Facilitate photovoltaic ("PV") and other forms of customer-sited distributed generation ("DG")
- Explore the use of biofuels in company generating units
- Promote the use of electric vehicles
- Continue a leading role in demand response management, aided by rapid deployment of advanced metering infrastructure ("AMI")
- Redesign residential rates to encourage conservation
- Continue involvement in energy efficiency programs for commercial and industrial customers
- Operate under a revenue decoupling mechanism "that closely tracks the mechanisms in place in for several California electric utilities"[2]. The mechanism for HECO would commence with the interim decision in the 2009 HECO rate case (most likely in the summer of 2009).

Concerning the approach to revenue decoupling, the Agreement states that "the utility will use a revenue adjustment mechanism based on cost tracking indices such as those used by the California regulators for their larger utilities or its equivalent and not based on customer

[1] Energy Agreement Among the State of Hawaii, Division of Consumer Advocacy of the Department of Commerce and Consumer Affairs, and the Hawaiian Electric Companies.

[2] *Ibid* p. 2.

count". The mechanisms would adjust the revenue requirement for the differences between the amount determined in the last rate case and:

(a) The current cost of operating the utility that is deemed reasonable and approved by the Hawaii Public Utilities Commission ("PUC");

(b) Return on and return of ongoing capital investment (excluding those projects included in the Clean Energy Infrastructure Surcharge); and

(c) Any changes in State or federal tax rates[3].

Costs of pensions and other post retirement benefits would be recovered by two separate tracking mechanisms.

The decoupling mechanisms are subject to review and approval by the Hawaii Public Utilities Commission ("Commission"). On October 24 2008, the Commission issued an order in Docket No. 2008-0274 initiating an investigation into the implementation of such mechanisms for the HECO companies. The Companies and the Consumer Advocate are directed to submit a joint proposal for a decoupling plan. The filing should take into account considerations and criteria set forth in a scoping paper on decoupling, prepared by David Magnus Boonin of the National Regulatory Research Institute ("NRRI"), which was procured by the Commission and released on January 21, 2009.[4]

Pacific Economics Group ("PEG") is a leading consultancy on alternative regulation for energy utilities. Revenue decoupling and the design of multiyear attrition mechanisms are company specialties. We have to date provided testimony in proceedings leading to the approval of ten decoupling plans, including several in California.

HECO has asked PEG to prepare a white paper with the mission of providing a foundation for the upcoming decoupling discussions. This is the final report on our research. The next section discusses the design of decoupling mechanisms. Revenue adjustment mechanisms are the primary focus. Section 3 discusses North American decoupling experience.

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[3] *Ibid*, p. 4.

[4] David Magnus Boonin, *Decoupling Utility Profits from Sales: Design Issues and Options for the Hawaii Public Utilities Commission.* National Regulatory Research Institute, January 2009.

We then discuss in Section 4 some of the pros and cons of decoupling that have been considered in regulatory hearings and the literature. Section 5 considers the application of revenue decoupling to HECO, HELCO, and MECO. Alternative RAMs are developed and results of financial sufficiency simulations are discussed. An Appendix traces the credentials of Dr. Mark Newton Lowry, senior author of this paper and the principle investigator for the project.

2. Decoupling Plan Design

In this section we provide an introduction to the design of decoupling mechanisms. Decoupling basics are first discussed. We then address in greater detail the design of revenue adjustment mechanisms.

2.1 Decoupling Basics

Revenue decoupling is an approach to utility regulation in which the special link that exists under traditional regulation between a company's earnings and the volume of its deliveries is relaxed or broken. The special linkage exists due to differences between the way in which a utility's cost is incurred and its base rate revenues are generated. Base rate revenues are those that compensate a utility for the cost of its non-energy inputs, which comprise capital, labor, materials, and services. Most utilities obtain the bulk of these revenues from volumetric charges. The meters of most residential and small business customers measure only volumes delivered. In the short run, delivery volumes have little impact on the cost of base rate inputs. The cost of these inputs is much more sensitive to changes in input prices, generation capacity, miles of transmission and distribution lines, and the number of customers served. Under these circumstances, changes in a utility's delivery volumes have a material impact on earnings. Utilities benefit financially when the volume delivered to each customer grows and are harmed financially when the volume per customer declines. A slowdown in volume per customer growth, such as might be achieved by aggressive programs to encourage conservation and customer-sited ("behind the meter") DG, erodes profits, and increases the need for a rate case.

2.1.1 Decoupling Mechanisms

Revenue decoupling can be accomplished in two fundamentally different ways. These are commonly referred to the "true up" approach to decoupling and straight fixed variable ("SFV") pricing. We discuss each approach in turn.

The True Up Approach to Decoupling

The true up approach to decoupling is most widespread today. The basic idea is a regularly scheduled sequence of rate adjustments that cause a company's actual revenues to track its revenue requirement more closely. True-up mechanisms typically involve a balancing account in which the difference between actual revenue and the revenue requirement is entered. The accumulated net balance, together with any interest that may be paid, provides the basis for a periodic rate adjustment. For example, the annual balance that accumulates at the end of the year might be added to the revenue requirement for the following year. In the typical "two way" decoupling mechanism, the rate adjustments to clear the balancing account are likely to take the form of surcharges in some years and credits in others.

Decoupling trueups are often applied to all customer classes. However, some plans decouple the revenue requirements of certain customer classes selectively. In these plans, decoupling typically applies to residential and/or commercial customers and excludes industrial customers.

The true-up approach to decoupling also typically involves a revenue adjustment mechanism ("RAM") to escalate the revenue requirement for changes in the business conditions that "drive" the cost of base rate inputs. This task is sometimes referred to as "recoupling"[5]. If a utility's billing determinants are growing, rates will actually *decline* with decoupling absent some form of revenue requirement escalation despite the fact that the cost of service normally rises due to input price inflation and output growth. Rate cases are another means of attaining attrition relief under true up mechanisms. The need for frequent rate cases will be exacerbated under conditions of brisk input price inflation and mounting investment needs.

[5] For early discussions of recoupling see Eric Hirst, *Statistical Decoupling: A New Way to Break the Link Between Energy Utility Sales and* Revenues, ORNL CON-372, Oak Ridge National Laboratory, 1993 and Joseph Eto, Steven Stoft, and Timothy Belden, *The Theory and Practice of Decoupling*, Lawrence Berkeley Laboratory paper LBL-34555 UC-350, January 1994.

SFV Pricing

The alternative approach to decoupling is to redesign rates to better reflect the short run impact that sales volumes, the number of customers served, maximum demand, and other billing determinants have on utility cost. Full decoupling can be achieved when volumetric charges are set at the short run marginal cost of volume growth and the balance of revenue is recovered from other charges. Customer charges and/or demand charges are commonly raised to achieve this goal in a revenue-neutral manner.

2.2 Revenue Adjustment Mechanisms

2.2.1 Introduction

The mechanism used to escalate the revenue requirement is one of the most important features of a true-up approach to decoupling. RAMs can substitute for rate cases as a means to adjust utility rates for trends in input prices, demand, and other external business conditions that affect utility earnings. This makes it possible to extend the period between rate cases without relaxing the just and reasonable standard for regulation. Performance incentives can be strengthened and regulatory cost trimmed.

Several approaches to RAM design have been established. Some RAMs adjust the revenue requirement formulaically to reflect new information (information obtained *after* the decoupling plan starts) about the business conditions that drive utility cost. Some of these formulaic RAMs make adjustments for price inflation and output growth. We will call this approach to RAM design full indexation. Other formulaic RAMs escalate the revenue requirement only for price inflation. We will call these "inflation only" RAMs.

A third category of formulaic RAMs is those that escalate the revenue requirement only for customer growth. Since this latter approach effectively freezes the revenue requirement per customer we will call it the revenue per customer (RPC) freeze approach. An RPC freeze may apply to the *total* revenue per customer. The formula may, alternatively, be applied to individual rate classes. The latter approach to RAM design was featured in a presentation made by Wayne Shirley of the Regulatory Assistance Project (RAP) in Honolulu in April 2008.

A second broad category of RAMs, which we will call all-forecast RAMs, are based solely on forecasts of future cost that are made prior to the start of the decoupling plan. This is tantamount to a rate case with multiple forward test years. The revenue requirement trajectories produced by this approach typically display a "stairstep" pattern. The stairsteps may reflect *expected* changes in business conditions during the decoupling plan but there are no automatic adjustments to the revenue requirement in the event that business conditions turn out to be different from those that were expected. The cost forecasts that provide the basis for stairsteps are frequently made using formulas similar to those used in formulaic RAMs. For example, a forecast of growth in operation and maintenance ("O&M") expenses might be based formulaically on forecasts of O&M price inflation and/or customer growth that are available at the time that the RAM is designed.

A third broad class of RAMs, which we will call hybrid RAMs, employ a mix of real-time formulaic adjustments and forecasting methods. In North America, hybrid RAMs most commonly feature real-time formulaic adjustments for O&M expenses. Some also feature adjustments for plant additions. The target rate of return on rate base is sometimes subject to separate adjustment during the term of the decoupling plan. Fixed forecasts are used for the cost of older plant using conventional cost of service methods.

A different approach to hybrid RAM design is used overseas. The revenue requirement is first established for a multi-year period using forecasting methods. Given forecasts of the revenue requirement, billing determinants, and a familiar macroeconomic measure of price inflation such as a consumer price index ("CPI"), a revenue escalation index is developed with general formula

$$growth\ CPI - X$$

that has an equivalent net present value. In this way, the revenue requirement is adjusted automatically for unexpected developments in price inflation.

2.2.2 Formulas for RAM Design

Index research has been used for more than twenty years to design formulas for utility rate and revenue requirement escalation. These provide the basis for formulaic and hybrid RAMs and can also be used in the cost forecasts needed for stairstep RAMs. We provide here a non-technical discussion of the use of indexing in RAM design. The discussion begins with consideration of some basic indexing concepts.

Basic Indexing Concepts

Price Indexes Price indexes are widely used in today's economy to measure price trends. Indexes can summarize the trends in the prices of multiple products by taking weighted averages of these trends. Indexes of trends in the prices a utility pays for its inputs customarily use *cost share* weights because these weights capture the impact of input price growth on cost.

Productivity Indexes Productivity (trend) indexes measure changes in the efficiency with which firms convert inputs to outputs. The growth trend of such an index is the difference between the trends in output and input quantity indexes.

$$trend\ Productivity = trend\ Output\ Quantities - trend\ Input\ Quantities\,. \qquad [1]$$

The output quantity index of a firm or industry summarizes trends in the amount of work that is performed. The input quantity index of an industry summarizes trends in the amounts of production inputs used. A total factor productivity ("TFP") index measures productivity in the use of *all* inputs. Indexes can also be designed to measure productivity in the use of operation and maintenance (O&M) inputs.

The sources of productivity growth can be diverse. One important source is technological change. New technologies permit an industry to produce given output quantities with fewer inputs. Economies of scale are a second source of productivity growth. These economies are available in the longer run when and if cost characteristically grows less rapidly than output. Incremental scale economies will typically be greater the more rapid is output growth.

An important short-run determinant of productivity growth is the intertemporal pattern of expenditures that must be made periodically but need not be made every year. Expenditures of this kind include those for replacement investment and maintenance. A fourth important source of productivity growth is changes in the miscellaneous other external business conditions that affect cost.

Application in RAM Design

Full Indexation The full indexation approach to RAM design takes full advantage of index logic. The analysis begins by considering that the growth trend in the revenue requirement of a utility industry operating under cost of service regulation equals the growth trend of its corresponding cost.

$$trend\ Revenue = trend\ Cost. \qquad [2]$$

We could, in principle, use relation [2] to regulate growth in the revenue requirement of a utility by having it equal the average trend in the corresponding cost of a group of peer utilities. This would be reasonable if those utilities faced similar trends in the number of customers served and other business conditions that drive cost growth.

Relation [2] implies that

$$Trend\ Revenue/Customer = trend\ Cost/Customer \qquad [3]$$

A utility's RPC can then, in principle, be escalated by the average growth in the base rate cost per customer of a peer group. The revenue requirement can be determined by multiplying the escalated RPC by the number of customers that the subject utility (*e.g.* HECO, HELCO, or MECO) serves. This approach would make it easier to identify a suitable peer group since companies would not have to have highly similar rates of customer growth. However, peers would still have to have similar trends in input prices and possibly other business conditions that drive cost growth.

A basic result of index logic is that the trend in a utility's cost is the sum of the trends in appropriately specified industry input price and quantity indexes:

$$trend\ Cost = trend\ Input\ Prices + trend\ Input\ Quantities. \qquad [4]$$

Suppose, next, that we use the number of customers to measure the effect of output growth on cost. Then

$$\begin{aligned} trend\ Cost &= trend\ Input\ Prices \\ &\quad - (trend\ Customers - trend\ Input\ Quantities) + trend\ Customers \\ &= trend\ Input\ Prices - trend\ Productivity + trend\ Customers. \qquad [5] \end{aligned}$$

The trend in cost decomposes into the trends in input price and productivity indexes and the number of customers served.

This is an important result for several reasons. One is that it demonstrates that a fully compensatory RAM should account for inflation, productivity, and customer growth. Another is that it provides the basis for a formulaic RAM that escalates revenue for a utility's own input price and output growth and uses peer group data only to establish a productivity target. Real-time inflation adjustments reduce the risk of input price volatility.

Relation [5] is one example of a full indexation formula for RAM design. An equivalent result can be obtained by escalating revenue per customer using the formula

$$trend\ Cost/Customer = trend\ Input\ Prices - trend\ Productivity \qquad [6]$$

and then using a utility's latest customer numbers to establish the new revenue requirement. A RAM with a design based on this formula is sometimes called a revenue per customer index. A full indexation formula is currently used in the revenue decoupling plan of Enbridge Gas Distribution (Canada's largest gas distributor) and was previously used by two large California utilities, Southern California Edison ("SCE") and Southern California Gas ("SCG").

The conceptual validity of full indexation formulas for RAM design has been widely acknowledged. Wayne Shirley has acknowledged their relevance on several occasions:

- Shirley's December 2000 RAP report entitled *PBR for Distribution Utilities* discusses inflation & productivity adjustments as normal part of RPC decoupling.
- Inflation & productivity are mentioned as considerations in "advanced" decoupling in a 2007 presentation to the Coalition for Clean Affordable Energy.
- Shirley notes adjustments for inflation and productivity in some approved California RAMs on page 27 of his April 2008 Hawaii presentation.
- Shirley also acknowledges the relevance of input price and productivity trends in RAM design in a 2008 report to Minnesota's PUC (*e.g.* p. 9: "a well designed decoupling program … possibly allows for adjustments according to changes in short term drivers such as numbers of customers, inflation, and productivity"), a 2008 presentation to New Mexico's PRC, a 2008 presentation to the Energy Efficiency Institute, and a 2006 presentation to an Arizona Decoupling Stakeholder Meeting.

Inflation Only RAMs Special, more simplified formulas are sometimes used in RAM design. For example, if customer growth is assumed to equal the productivity growth target, relation [5] simplifies to

$$trend\ Cost = trend\ Input\ Prices. \qquad [7]$$

This formula is featured in many hybrid RAMs, where it is used to escalate O&M expenses. A good example is the O&M cost escalator in the current RAM of SCE. Relation [7] makes the most sense for utilities facing customer growth that is similar to a reasonable productivity growth target. However, it will tend to undercompensate companies with unusually rapid customer growth.

Our analysis suggests that an escalation formula that accounts for inflation and productivity growth but not for customer growth will be uncompensatory. The resultant financial attrition will be greater to the extent that customer growth is rapid. However, it is possible to construct a fixed X factor for a RAM formula that is the difference between a reasonable productivity target and expected customer growth.

$$\begin{aligned} \textit{Trend Cost} &= \textit{trend Input Prices} - (\textit{trend Productivity} - \textit{trend Customers}) \\ &= \textit{trend Input Prices} - X. \end{aligned} \quad [8]$$

Inflation Measures

Resolved that a fully compensatory RAM reflects input price inflation, other important design issues must still be addressed. One is whether it should be expressly designed to track *input* price inflation. There are numerous precedents for the use of industry-specific inflation measures in RAMs, most notably in the indexation of O&M expenses in hybrid RAMs. However, some RAMs instead feature measures of *macroeconomic* inflation, such consumer price indexes (CPIs) and the gross domestic product price index ("GDPPI"), which measure inflation in the prices of the economy's final goods and services. Final goods and services consist chiefly of consumer products but also include government services and capital equipment.

Macroeconomic inflation measures have noteworthy advantages over industry-specific measures in RAM formulas. They are available from respected and impartial sources such as the Federal government and their use is unrestricted. Suitable summary indexes of utility input price inflation are not available from such sources. Customers are familiar with a few macro inflation measures and this facilitates acceptance of RAMs . There is no need to go through the chore of calculating a custom input price index. Controversies over the design of an industry-specific price index are sidestepped. These controversies can be especially great when the index is designed to measure capital cost. Note, finally, that CPIs are available for Honolulu that reflect inflationary conditions in Hawaii.

The argument against the use of macro inflation measures in RAMs is that they are not designed to track utility industry input price trends. One problem is that measures of trends in the economy's *output* prices, such as CPIs or GDPPIs, are not good estimates of the trend in the economy's *input* prices since they reflect the productivity growth of the economy in the use of production inputs[6]. The economy's productivity growth has, like that in the electric power industry, been substantial in recent years, averaging more than 100 basis points annually. A second problem is that the trend in the economy's input prices may differ from the corresponding trend for utilities. Utilities, after all, use a lot more capital than the typical business in the economy.

Note, thirdly, that many CPIs display a higher degree of instability than may be typical of utility inputs. A case in point is the CPI – all items ("CPI-U") for Honolulu. This index occasionally registers negative inflation and has accelerated markedly in recent years.

When a macroeconomic inflation measure is used in a RAM formula, it follows that the revenue escalation formula may need some calibration if it is to track the industry cost trend. Suppose, for example, that the inflation measure is a CPI. In that event we can restate relation [6] as

growth Cost/Customer =

growth CPI – [*trend Productivity* +(*trend CPI* – *trend Input Prices*)] [9]

The term in parentheses may be called an "inflation differential". It helps the RAM track cost when CPI is the inflation measure since the X factor is calibrated to reflect any tendency of the CPI to grow more rapidly or more slowly than an industry specific price index.

Productivity Targets

Full indexation formulas (*e.g.* those based on relations [5], [6], [8], or [9]) require a productivity growth target. In the United States, the productivity targets commonly used in index-based regulation are the average productivity growth rates of a group of utilities. The productivity peer group is sometimes the full national sample and sometimes a sample of companies in the surrounding region. There are no regional peers for the Hawaiian Electric companies in available US data sets.

[6] In much the same manner, an index of the trend in the utility industry's rates would reflect its productivity growth and not be a good measure of its input price inflation.

2.2.3 Revenue Per Customer Freezes

Revenue per customer freezes were noted in Section 2.2 to be a common form of formulaic RAM.[7] Relation [6] reveals that an RPC freeze provides appropriate compensation for cost growth only when a company's input price growth is similar to a reasonable target for its productivity growth. This assumption is generally unreasonable. Research by PEG for HECO reveals that the productivity trend of vertically integrated electric utilities is similar to that of the U.S. private business sector as a whole. As such, it is likely to be well below the pace of input price inflation.

In other research for HECO, PEG has calculated the trends in the base rate cost per customer of a sample of 43 vertically integrated utilities. Results are found in Table 1 and Figure 1. It can be seen that the average utility experienced cost per customer growth that was well above zero from 1996 to 2006. Growth accelerated materially in the last four years of the sample period. Results for 2007 have not yet been processed.

Our research suggests that RPC freezes are substantially uncompensatory as the primary basis for adjusting utility revenue requirements. This is a particular concern in states with historic test years since the test year revenue requirement will already reflect dated inflation assumptions. The inadequacy of RPC freezes as mechanisms for full attrition relief is doubtless one of the reasons that utilities who operate under such freezes typically reserve the right to file rate cases during the decoupling plan.[8] Many have done so in recent years, as we discuss further in Section 3.

2.2.4 All Forecast RAMs

Our discussion suggests that all forecast RAMs should take account of inflation, productivity, and customer growth trends to be fully compensatory. All forecast RAMs have several advantages in accomplishing this goal. One is that they can sidestep the complex issue of input price and productivity measurement. Complexity is especially great in the measurement of

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[7] An early discussion of this approach to RAM design is found in David Moskovitz, *Profits and Progress Through Least Cost Planning*. Washington DC, National Association of Regulatory Utility Commissioners, 1989.

[8] Moskovitz and Swofford note that "The RPC decoupling method is not designed to change the length of time between utility rate cases. The utility remains free to initiate a general rate case if its financial condition requires it." See David Moskovitz and Gary B. Swofford, "Revenue per Customer Decoupling" in Steven M. Nadel, Michael W. Reid and David R. Wolcott, eds. *Regulatory Incentives for Demand-Side Management*. Washington, D.C. and Berkeley CA, American Council for an Energy Efficient Economy, 1992.

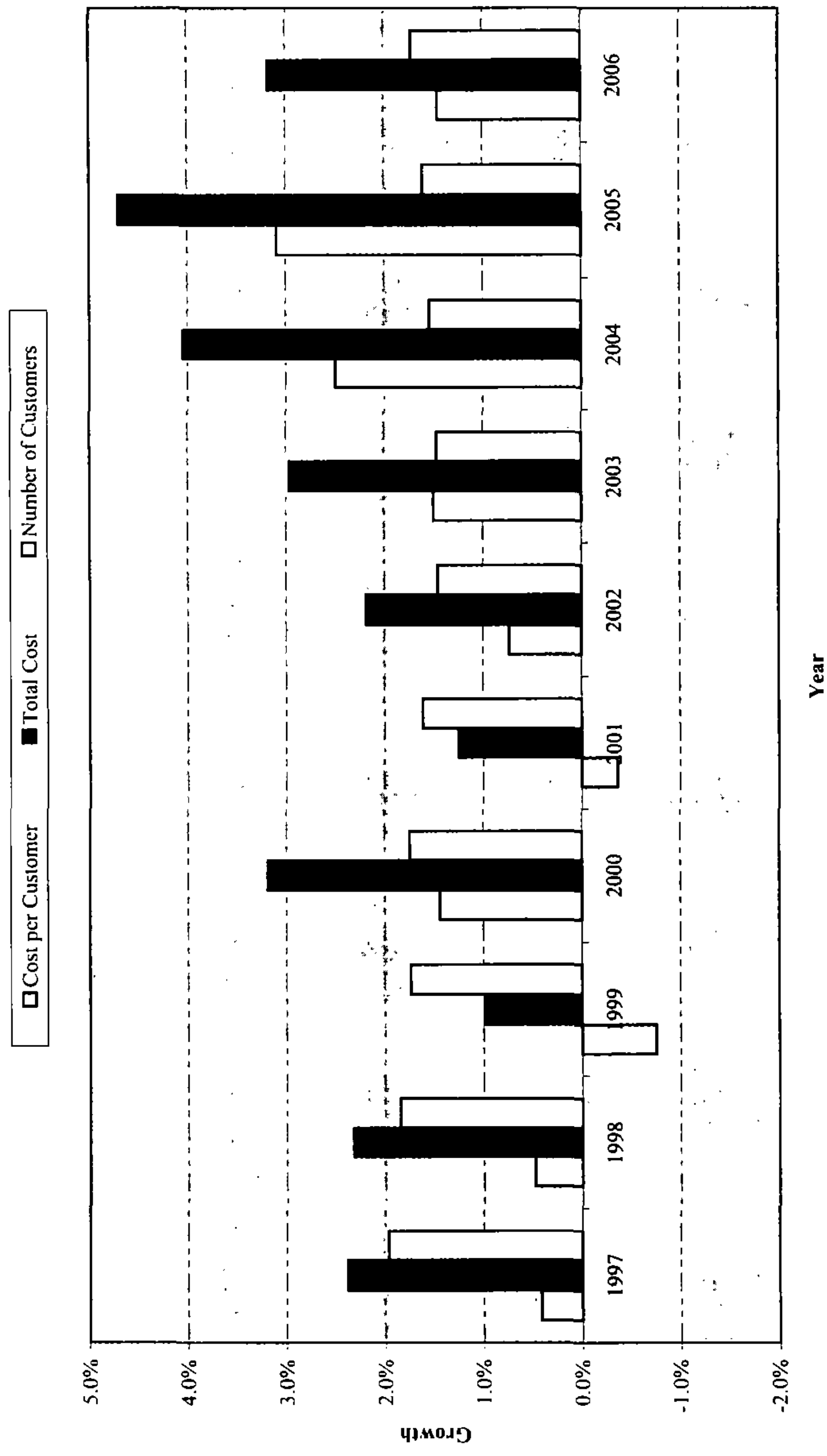
Table 1

Trends in Bundled Power Distributor Cost per Customer, 1996-2006

	Total Cost		Customer Numbers		Cost per Customer	
Year	Index	Growth Rate	Index	Growth Rate	Index	Growth Rate
1996	1.000		1.000		1.000	
1997	1.024	2.4%	1.020	2.0%	1.004	0.4%
1998	1.048	2.3%	1.039	1.8%	1.009	0.5%
1999	1.059	1.0%	1.057	1.7%	1.001	-0.8%
2000	1.093	3.2%	1.076	1.7%	1.016	1.4%
2001	1.107	1.3%	1.093	1.6%	1.012	-0.4%
2002	1.131	2.2%	1.109	1.5%	1.020	0.7%
2003	1.165	3.0%	1.126	1.5%	1.035	1.5%
2004	1.213	4.0%	1.143	1.5%	1.061	2.5%
2005	1.272	4.7%	1.162	1.6%	1.095	3.1%
2006	1.313	3.2%	1.182	1.7%	1.111	1.5%
Average Annual Growth Rate						
1996-2006		**2.72%**		**1.67%**		**1.05%**
1996-2001		**2.03%**		**1.78%**		**0.24%**
2001-2006		**3.42%**		**1.56%**		**1.86%**

Figure 1

Cost per Customer Growth for Bundled Power Distributors, 1996-2006



capital cost. Many participants in the regulatory arena are unfamiliar with the measurement of capital price and quantity trends. Another advantage of all forecast RAMs stems from the fact that full indexation RAMs usually reflect a judgment concerning *long* run industry productivity trends. The resultant productivity targets are often unsuitable for funding the surges in major plant additions that utilities sometimes make.

The chief downside to using all forecast RAMs is their rigidity. Inflation and other business conditions that effect utility cost do not always turn out as forecasted. The result can be windfall gains or losses for utilities and higher operating risk.

2.2.5 Hybrid RAMs

The hybrid approach to RAM design was noted in Section 2.2.1 to use a mix of formulaic and forecasting methods. In North America, hybrid RAMs have the following typical features.

- Budgets for non-energy O&M expenses are escalated automatically during the decoupling period using formulas that reflect new information. These formulas usually involve an inflation measure and may also make adjustments for customer and productivity growth.
- Plant addition budgets are set using a mix of forecasting and indexation. The budget for each year is often fixed in real terms, with an adjustment in the "out" years of the plan for new information about inflation. Major plant additions are sometimes subject to separate treatment.
- The future budget for the cost of plant ownership is otherwise forecasted using traditional cost of service methods. This is fairly straightforward inasmuch as the depreciation and return on rate base that result from a set of older investments and predetermined plant additions is straightforward to calculate. The most unpredictable element, the cost of obtaining funds in capital markets, is sometimes subject to separate adjustments during the decoupling plans to reflect new information.

This general approach to RAM design has a number of advantages. Indexing is used where it is least controversial, as in the escalation of O&M expenses. There is no need for the complex calculations needed to measure input price and productivity trends for utility plant. The formulas permit adjustments for new information about inflation. The treatment of capital cost is flexible enough to accommodate surges in plant additions.

O&M Expenses

The well established logic of economic indexes provides a useful general formula for escalating O&M expenses. The formula includes an index of growth in wages and other prices of O&M inputs, a measure of growth in the output that "drives" these expenses (*e.g.* the number of customers served), and a target for the trend in the productivity of O&M inputs:

$$growth\ Cost^{O\&M} = growth\ Input\ Prices^{O\&M} - trend\ Productivity^{O\&M} + growth\ Customers. \qquad [10]$$

The growth of the input price index is a weighted average of the growth in various price subindexes, such as the salaries and wages of different groups of workers and different categories of materials and services. The weight for each input category j reflects its share in total O&M expenses ("sc_j").

$$growth\ Input\ Prices^{O\&M} = SUM_j\ sc_j\ growth\ Input\ Price_j. \qquad [11]$$

Formulas like these were used to escalate the O&M expenses of San Diego G&E in its hybrid RAMs for gas and electric service from 1994 to 1999.

Consider now that if the O&M productivity growth target equals the growth of customers formula [1] simplifies to the growth in the input price index:

$$growth\ Cost^{O\&M} = growth\ Input\ Prices^{O\&M} \qquad [12]$$

An equivalent and more popular approach has been to separately escalate each category of cost by its corresponding input price index.[9]

$$Cost_{t+1}^{O\&M} = SUM_j\ Cost_{j,t}\ x\ growth\ Input\ Prices_{j,t+1}^{O\&M} \qquad [13]$$

This is approach that has been used most commonly in hybrid RAMs in California.

[9] The equivalency is easy to demonstrate since if
$Cost_{t+1}^{O\&M} = SUM_j\ Cost_{j,t}\ x\ growth\ Input\ Prices_{j,t-1}^{O\&M}$
then $Cost_{t+1}^{O\&M} / Cost_t^{O\&M} = SUM_j (Cost_{j,t} / Cost_t)\ x\ growth\ Input\ Prices_{j,t-1}^{O\&M}$

One problem with the disaggregate approach is that the likely productivity growth of different kinds of inputs varies widely. For example, productivity tends to grow more rapidly in the use of labor than in the use of materials and services. Escalating salaries and wages for the growth in their prices will then tend to overcompensate a utility for typical cost growth. But this will be offset by the tendency of the M&S escalators to be undercompensatory.

Measures of macroeconomic output price inflation such as consumer price index (CPI) are occasionally used in O&M cost escalation formulas instead of an explicit input price index.[10] For example, the general formula

$$growth\ Cost^{O\&M} = growth\ CPI - X + growth\ Customers. \qquad [14]$$

has been used in hybrid RAMs in Ontario, Canada and Victoria, Australia.

We have seen that measures of macroeconomic output price inflation will tend to *under*state O&M input price inflation in the long run since they reflect the (recently substantial) growth in the productivity of the economy. In other words, the CPI already reflects the substantial productivity growth of the economy. This problem can be rectified by adding an inflation differential to the formula:

$$\begin{aligned} growth\ Cost^{O\&M} &= growth\ CPI - [growth\ Productivity^{O\&M} + (trend\ CPI - trend\ Input\ Prices^{O\&M})] \\ &\quad + growth\ Customers \qquad [15] \end{aligned}$$

Plant Additions

The index logic used to establish O&M budgets in hybrid RAMs is less useful --- and rarely used --- in establishing plant addition budgets. The reason is that capital spending is a complex function of past spending patterns (*i.e.* system age) and current and expected future system growth. Major plant additions are sometimes needed that are markedly higher than recent historical levels.

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[10] The resultant formula can in principle include, additionally, a term to correct for any tendency of the macro inflation measure to overstate or understate O&M input price inflation.

In practice, the plant addition budgets of hybrid RAMs are usually fixed in real terms and escalated for inflation, as in the following formula:

$$Additions_t = Additions_{base} \text{ x } Construction\ Cost_t / Construction\ Cost_{base} \qquad [16]$$

The major issue in the design of the formula is the basis for the base budget. Other issues may include the choice of the inflation measure used in the formula, whether major plant additions are excluded, and what happens when expenditures deviate from the budgeted level. With regard to the first issue, our review of the precedents reveals that the base plant addition budget has most frequently been set at the average level of capex in recent years. The base budget may, alternatively, be that established in the most recent forward test year or be set using an econometric model. An econometric model in a hybrid RAM for SDG&E set the plant addition budget on the basis of customer growth and the previous value of plant.

With regard to inflation measures, Whitman Requardt and Associates maintains "Handy Whitman" indexes of public utility construction costs. Summary indexes are available for vertically integrated electric utilities. The one that would seem to match HECO best is that for All Steam Generation, which excludes nuclear and hydroelectric generation. Indexes are also available for specific utility functions such as transmission and distribution. Indexes are reported for regions of the United States (*e.g.* the Pacific region) but there is no summary index for the nation as a whole. There are no Handy Whitman indexes for Hawaii. However, a Honolulu Bank maintains construction cost indexes that are published in the *Hawaii Data Book.*

3. Decoupling Experience

3.1 Decoupling Precedents

This section provides a brief review of the history of revenue decoupling in California and other jurisdictions. Revenue adjustment mechanisms are a central focus. Precedents for the revenue decoupling are listed in Tables 2 and 3. These tables include details of RAM design.

3.1.1 California

Overview

The bulk of North American experience with revenue decoupling has occurred in California. Decoupling began there in the late 1970s when a generic proceeding of the California Public Utilities Commission ("CPUC") lead in Decision 88835 to approval of supply adjustment mechanisms for the state's natural gas utilities. These mechanisms were designed to encourage conservation and protect companies from the financial consequences of declines in throughput that were due to supply curtailments and to rate designs with high volumetric charges. Decoupling was to be effected by trueups using balancing accounts. The generic decision did not address the issue of RAM design. However, gas utilities proposed RAMs and secured approval in their subsequent filings.

California gas services have been subject to decoupling in most years since its inception. All of the major companies are subject to decoupling at present. Decoupling has generally been less extensive for "non-core" services than for services to core (*e.g.* residential and small business) customers.

A proposal by Pacific Gas & Electric (PG&E) to decouple its electric service revenues was rejected by the CPUC in 1978. In 1980 the CPUC approved in D. 92549 a "one way" decoupling mechanism for Southern California Edison (SCE) that returned surplus revenues to customers but not shortfalls. Uncertainty concerning future sales volumes was the Commission's principle stated concern in approving the provision.

In 1982 the CPUC instituted two-way decoupling mechanisms, called Electric Revenue Adjustment Mechanisms (ERAMs), for PG&E and San Diego Gas & Electric. An ERAM was instituted for SCE in 1983, and for Pacific Power & Light in 1984.

Table 2

APPROVED PRECEDENTS FOR REVENUE ADJUSTMENT MECHANISMS

Jurisdiction	Company Name	Services	Years in Place	Description of Revenue Adjustment Mechanism
				Hybrid RAMs
CA	Pacific Gas & Electric	Electric	1982-1983	**Hybrid O&M:** Labor cost escalated by 3% + (74% * growth in CPI). Non-labor cost escalated by DRI forecast of growth in the PPI for industrial commodities **Capex:** 5-year historic average of plant additions per customer, escalated for inflation, with additional allowance for approved major projects. ROR was forecasted. First instance of the Electric Revenue Adjustment Mechanism (ERAM) in California.
				Decision 93887
CA	Pacific Gas & Electric	Electric	1984-1985	**Hybrid O&M:** Labor cost escalated by negotiated wage increases between PG&E and trade union. Non-labor cost escalated by 70% * growth in PPI for Industrial Commodities + 30% growth in CPI-Wage Earners. **Capex:** 5-year historic average of plant additions per customer, escalated for inflation, with additional allowance for approved major projects
				Decision 83-12-068
CA	Pacific Gas & Electric	Electric	1986-1989	**Hybrid O&M:** Labor cost escalated by in-place contract fixed rate, the forecasted growth in CPI-U, and/or utility wage formula reflecting the union contract agreement. Non-labor cost escalated by actual inflation in the preceding year **Capex:** 5-year historic average of plant additions per customer, escalated for inflation. PG&E wanted customer growth to also be factored into the escalation of expenses and capex, however the CPUC stated that they expected productivity gains to cancel out the extra costs of customer growth. This decision also mandated that California utilities file productivity studies with the CPUC in all future general rate case proceedings.
				Decision 85-12-076
CA	Pacific Gas & Electric	Electric	1990-1992	**Hybrid O&M:** Labor cost escalated by growth in CPI-Wage Earners. Non-labor escalated by growth in a custom materials & services index (MSI). The MSI is a company-specific cost weighting of expense categories that uses various DRI electric utility price indexes. **Capex:** 5-year historic average of additions per customer, escalated for inflation
				Decision 89-12-057
CA	Pacific Gas & Electric	Electric	1993-1995	**Hybrid O&M:** Labor cost escalated by growth of CPI-Wage Earners. Non-labor cost escalated by MSI as calculated in the previous PG&E plan. **Capex:** 5-year historic average of additions per customer, escalated for inflation
				Decision 92-12-057
CA	San Diego Gas & Electric	Gas	1978-1981	**Hybrid O&M:** Escalated by forecasted growth of DRI price indexes. **Capex:** Based on forecasted plant additions.
				Decision 88835
CA	San Diego Gas & Electric	Electric & Gas	1982-1983	**Hybrid O&M:** Labor costs escalated by growth in CPI-All Urban Consumers as forecasted by DRI's November 1982 econometric survey. Non-labor costs escalated by growth in DRI's November 1982 forecast of PPI-Finished Goods. **Capex:** Four-year average of plant additions escalated by the non-labor escalation factor for 1981-1983
				Decision 93892

Jurisdiction	Company Name	Services	Years in Place	Description of Revenue Adjustment Mechanism
CA	San Diego Gas & Electric	Electric & Gas	1986-1988	**Hybrid O&M:** O&M is escalated using growth of numerous DRI electric utility price indexes to construct an industry input price index **Capex:** Based on forecasted plant additions and is adjusted in its attrition filing for the change in inflation rates (gathered from D. 88-12-085).
				Decision 85-12-108
CA	San Diego Gas & Electric	Electric	1989-1993	**Hybrid O&M:** Escalated by growth of DRI electric utility price indices.**Capex:** 4-year historic average of recurring plant additions, no longer adjusted for inflation in attrition filings
				Decision 89-11-068
CA	San Diego Gas & Electric	Electric & Gas	1994-1999	**Hybrid O&M:** Escalated by Inflation Factor + 58%*(Customer Growth - productivity of 1.5%). All terms set separately for electric and gas O&M. Inflation factor is cost-weighted average of the growth in SDG&E's labor cost and DRI's gas- or electric-specific non-labor price indexes. **Capex:** Determined by regressions on new customer growth and inflation (Handy Whitman inflation index) expectations. Electric capex in year t = [4.23% + .52(% change in N) - .28(% change in N lagged one year)] * previous years gross plant. Gas capex in year t = [2.94% + .3*(% change in gas customers)]*previous year's gross plant Thus, additions are a function of existing customers, customer additions in year t, lagged customer additions, and "capital intensity" measured by existing network plant per customer. Regressions were based on SDG&E capex data from 1952-1992 Unclear if capex is adjusted in "real time" or based on forecasts of customer growth and set ahead of time for each attrition year
				Decision 94-08-023
CA	Southern California Edison	Electric	1983-1984	**Hybrid O&M:** Labor cost escalated by fall 1983 DRI forecasts of CPI-U. Non-labor cost escalated by fall 1983 DRI forecasts of a modified producer price index **Capex:** 7-year historical average of plant additions, excluding major plant additions, divided per added customer. This ratio is then multiplied by the forecasted customer additions to determine the capex in the 1984 attrition year Estimated major generation plant additions added to this capex forecast
				Decision 82-12-055
CA	Southern California Edison	Electric	1986-1991	**Hybrid O&M:** Labor cost escalated by in-place contract fixed rate, the forecasted CPI-U, or utility wage formula reflecting the union contract agreement. Non-labor cost escalated by actual inflation of preceding year. **Capex:** Based on forecasts. This decision also mandated utilities to file productivity studies in all future general rate case proceedings
				Decision 85-12-076
CA	Southern California Edison	Electric	2004-2006	**Hybrid O&M:** Salaries and wages are escalated by an index constructed from Global Insight salary and wage prices. Materials and Services cost categories are escalated. Global Insight indexes for electric utilities are used for both the labor and M&S input price indexes. A health care price index is also used to escalate health care costs. **Capex:** SCE will include capex associated with budget-based forecast in PTYR filing, with the baseline being the 7-year historic average of capex. Adjustment made for actual capex, such that if capex is below the budgeted amount ratepayers will receive a refund through the Capital Additions Adjustment Mechanism (CAAM)
				Decision 04-07-022
CA	Southern California Edison	Electric	2006-2008	**Hybrid O&M:** Salary and wages are escalated by a weighted index. Materials and Services cost categories are escalated. Global Insight indexes are used for both the labor and M&S input price indexes. A health care price index is also used to escalate health care costs. **Capex:** Based on 2006 budget approved previously, then escalated by 2.5% for each attrition year
				Decision 06-05-016

Jurisdiction	Company Name	Services	Years in Place	Description of Revenue Adjustment Mechanism
CA	Southern California Gas	Gas	1986-1989	**Hybrid O&M:** Labor cost escalated by in-place contract fixed rate, the forecasted CPI-U, or utility wage formula reflecting the union contract agreement. Non-labor cost escalated by actual inflation of preceding year. **Capex:** 2-year historic average of plant additions, escalated for inflation by PPI for manufacturing. No additional allowance for approved major projects. This decision also mandated utilities to file productivity studies in all future general rate case proceedings
				Decision 85-12-076
CA	Southern California Gas	Gas	1990-1993	**Hybrid O&M:** Same attrition adjustments for O&M as found in D. 85-12-076. **Capex:** Attrition year capital expenditures set at the test year level in 1990.
				Decision 90-01-016
NY	Consolidated Edison	Gas	2007-2010	**Hybrid** Revenue per customer escalated by smoothed forecasted. Decision resulted in forecasted revenue increases of 11.2% in year 1, 10.1% in year 2, and 9.2% in year 3. Company forecasted capex by dividing capex into "recuring" costs and then adding in "2008-2010 Rate Case Projects" that were special projects forecasted to occur in the attrition years.
				Case 06-G-1332
VT	Vermont Gas Systems	Gas	2006-2009	**Hybrid** O&M expenses per customer escalated annually. Capital cost exempted.
				Docket No. 7109
				All Forecast RAMs
CA	Pacific Gas & Electric	Electric Dx/Gen & Gas	2007-2010	**All forecast** Attrition factors from settlement (excluding costs for Diablo Canyon refueling outage in 2009). 2008: 2.5%; 2009, 2 5%; 2010: 2.4%. PG&E forecasts based on labor and benefit costs and certain non-labor expenses. A number of forecasted indexes from Global Insight were used. Hundreds of capital expenditures were forecasted by PG&E to determine the capex in the attrition years.
				Decision 07-03-044
CA	PacifiCorp	Electric Gen/Dx	1984-1985	**All Forecast** O&M budget forecsts based on DRI forecasts of escalation of labor and non-labor prices. Capex based on staff's forecasts
				Decision 89-09-034
CA	San Diego Gas & Electric	Electric & Gas	2008-2011	**All Forecast** Attrition year revenue requirement increases of $41 million in 2009 and $44 million in both 2010 and 2011
				Decision 08-07-046
CA	Southern California Gas	Gas	1979-1980	**All Forecast:** Two year rate plan where a higher ROE (13.49%) was approved to compensate SCG for anticipated increased costs in the second year.
				Decision 89710
CA	Southern California Gas	Gas	1981-1982	**All Forecast** Attrition allowance of $45 million granted "which reflects our best judgment of the level of attrition expected for 1982."
				Decision 92497
CA	Southern California Gas	Gas	2008-2011	**All Forecast** Attrition year revenue requirement increases of $52 million in 2009, $51 million in 2010, and $53 million in 2011.
				Decision 08-07-046
NY	Consolidated Edison	Electric	2008-open	**All Forecast** Class specific revenue targets are forecasted and actual revenues are "trued up" on a class specific basis. Set revenues for March 2008 through March 2009. no multiyear forecasts included as these will be determined in an ongoing proceeding.
				Case 07-E-0523

Jurisdiction	Company Name	Services	Years in Place	Description of Revenue Adjustment Mechanism
NY	Niagara Mohawk	Electric	1990-1992	**All Forecast** Establishes the Niagara Mohawk Electric Revenue Adjustment Mechanism (NERAM) that reconciles approved margins with actual margins. NERAM is initiated if the difference in projected and actual revenues is greater than $10 Million within a six-month period. Settlement agreed to revenue increases of 6 9%, 2.9% and 1.9% were approved for RY1, RY2, and RY3. Could not obtain initial company proposals to determine methods of forecasting revenues
				Case 94-E-0098
NY	Orange & Rockland Utilities	Electric	1991-1993	**All Forecast** Revenue decoupling mechanism (RDM) put into place that reconciles actual revenues with approved revenues. Forecasts from the test year are determined by breaking expenses into 3 categories. Category one is controllable costs where the utility can control the quantity, these costs are escalated by projected inflation. Inflation measure is the forecast of the GNP Price Deflator Index as published in the latest available publication of the "Blue Chip Economic Indicators" adjusted for the difference between the overal CPI Index and the CPI Index excluding medical costs. Category 2 are costs where price is controllable but quantity purchased is not (purchased power costs), these costs have a forecasted price and there will be subsequent adjustments for the actual quantity purchased. Category 3 are costs that are unpredictable/uncontrollable (wage rates, property taxes, and medical, property, and liability insurance), these costs are annually adjusted to reconcile the rate case allowances to actual expenditures. The RDM provides for annual updates to the revenue requirement allowance to reflect capital additions. So capital cost is updated annually, except for the ROE which is set at 11.45% for the duration of the plan.
				Case 89-E-175
NY	Orange & Rockland Utilities	Electric	2008-open	**All Forecast** Forecasted increase distributed evenly in 2 5% annual adjustments for each customer class. Labor price escalated by 3.5% minus a 1% productivity adjustment (2.5% overall). Labor quantity forecasted to increase by a projected amount of employees each year. Materials and other expenses escalated by an inflation rate of 2.1% (unless inflation exceeds 4% in a year and the company earns less than a 9.4% ROE, then added expenses due to excess inflation will be deferred for future recovery). Capex was based on company forecasts.
				Case 07-E-0949
NY	Rochester Gas & Electric	Electric	1993-1996	**All Forecast** Electric revenues subject to an Electric Revenue Adjustment clause (ERAM) that trues up the approved revenues with actual revenues. The settlement agrees to electric revenue increases of 2.75% in RY1, 2.98% in RY2, and 2.98% in RY3. Base rate costs that were determined to be "non-controllable" include R&D, government assessments, and the earnings and actuarial assumptions underlying the accruals for pensions and other post employment benefits. Such costs, other than fuel, amount to 11% of operating expenses and are re-forecasted annually. *All other expenses, other than fuel, are subject to the true-up via the ERAM.* The order claims that most expenses were escalated based on expected inflation. Plan includes an Integrated Resource Management Incentive (IRMI) that uses an external benchmark of the 7 investor-owned utilities in the New York Power Pool and rewards or penalizes RG&E based on its cost trend in comparison to the benchmarks trend. This is the first time an IRMI has been implemented in New York.
				Opinion No. 93-19
NY	New York State Electric & Gas	Electric	1993-1995	**All Forecast** Electric revenues subject to a Revenue Decoupling Mechanism (RDM) that adjusts for the difference in allowed revenues and actual revenues. Forecast procedures are similar to those of the RG&E plan (Opinion 93-19) A Production Cost Incentive (PCI) put in place to provide rewards and penalties for power production trends compared to a 19 utility external benchmark.
				Opinion No. 93-22

Jurisdiction	Company Name	Services	Years in Place	Description of Revenue Adjustment Mechanism
NY	Consolidated Edison	Electric	1992-1995	**All Forecast** Electric revenues subject to a Revenue Decoupling Mechanism (RDM) that adjusts for the difference in allowed revenues and actual revenues. Non-fuel O&M costs are forecasted based on projected inflation rates except for labor wages, property taxes, HIECA, and R&D which are subject to annual reconciliation. Rate base is reconciled annually based on actual capital expenditures and depreciation. ROE is set at 11.5% in RY1, and 11.6% in RY2 and RY3
				Opinion No. 92-8
NY	Long Island Lighting Company	Electric	1992-1994	**All Forecast** Electric revenues subject to a Revenue Decoupling Mechanism (RDM) that adjusts for the difference in allowed revenues and actual revenues. Non-fuel O&M costs are forecasted based on projected inflation rates except for labor wages, property taxes, and DSM expenses which are subject to annual reconciliation. Rate base reconciled annually based on actual capital expenditures and depreciation.
				Opinion No. 92-8
OR	Portland General Electric	Electric	1995-1996	**All Forecast** Revenue path set out in earlier phase of proceeding.
				Order No. 95-0322

Full Indexation RAMs

Jurisdiction	Company Name	Services	Years in Place	Description of Revenue Adjustment Mechanism
CA	PacifiCorp	Electric	2007-2009	**Full Indexation** Settlement establishes the Post Test Year Adjustment Mechanism (PTAM). PTAM = Inflation based on Sept. of the prior year Global Insight forecasts of CPI for the attrition year with an off-setting 0.5% productivity factor.
				Decision 06-12-011
CA	Southern California Gas	Gas	1998-2002	**Full Indexation** Revenue per customer escalated by growth IPI-X; IPI is cost-weighted (average weights of 3 major CA gas *utilities) index of DRI-forecasted capital, labor, and materials indexes. IPI is then "trued up" to adjust for the difference in the* actual IPI and the forecasted one used to set rates in the attrition year.
				Decision 97-07-054
CA	Southern California Edison	Electric	2002-2003	**Full Indexation** Attrition factor is growth CPI - X + growth N x M. X set to 1.6% as before. Growth N is total customer growth, and M is Commission-set marginal cost of customer connection (M = $657).
				Decision 02-04-055
OR	PacifiCorp	Electric	1998-2001	**Full Indexation** The growth in Revenue = growth GDPIPI - 0.3% productivity factor + growth Volume (revenue-weighted by class).
				Order No. 98-191
Ontario	Enbridge Gas Distribution	Gas	2008-2012	**Full Indexation** Revenue per customer escalated by growth GDPPI - X.
				Docket EB-2007-0615

Inflation Only RAMs

Jurisdiction	Company Name	Services	Years in Place	Description of Revenue Adjustment Mechanism
CA	*Pacific Gas & Electric*	*Gas*	*1978-1985*	**Inflation Adjustment Only** Revenue Growth = growth CPI. Bounds on minimum and maximum inflation adjustment set.
				Decision 89316
CA	Pacific Gas & Electric	Gas & Elec Dx/Gen	2004-2006	**Inflation Adjustment Only** Attrition Factor is forecasted CPI-U. Additional 1% in 2006 only. Bounds on minimum and maximum inflation adjustment set
				Decision 04-05-055

Jurisdiction	Company Name	Services	Years in Place	Description of Revenue Adjustment Mechanism
CA	San Diego Gas & Electric	Gas & Elec	2005-2007	**Inflation Adjustment Only** Attrition factor is forecasted growth in CPI-U. There is no "true up" to the actual CPI compared to the forecasted. However, in the second attrition year the actual CPI for the preceding year will be used to reset the revenue requirement for that year and then recalibrated RR will be escalated based on the forecasted CPI This eliminates an error in forecasted CPI from affecting future attrition years Bounds on minimum and maximum inflation adjustment set
				Decision 05-03-025
CA	Southern California Gas	Gas	2005-2007	**Inflation Adjustment Only** Attrition factor is forecasted growth inCPI-U. There is no "true up" to the actual CPI compared to the forecasted. However, in the second attrition year the actual CPI for the preceding year will be used to reset the revenue requirement for that year and then recalibrated RR will be escalated based on the forecasted CPI. This eliminates an error in forecasted CPI from affecting future attrition years. Bounds on minimum and maximum inflation adjustment set
				Decision 05-03-025
Revenue Per Customer Freezes				
AR	Arkansas Oklahoma Gas	Gas	2007-2011	**RPC Freeze**
				Docket 07-026-U
AR	Arkansas Western	Gas	2007-2009	**RPC Freeze**
				Docket 06-124-U
AR	CenterPoint Energy	Gas	2008-2010	**RPC Freeze**
				Docket 07-081-TF
CO	Public Service Co of CO	Gas	2008-2010	**RPC Freeze:** Partial Revenue Decoupling Adjustment made for residential class only. Revenues are only recovered from lost revenue resulting from weather normalized use per customer declining more than 1.3% per year. Revenues that are lost from declines in use per customer under 1 3% are not recoverable. To the extent that weather normalized use per customer rises, Public Service will not be required to implement a negative rider
				Decision C07-0568
FL	Florida Power Corporation	Electric	1995-1997	**RPC Freeze**
				Docket 930444
ID	Idaho Power	Electric	2007-2009	**RPC Freeze**
				Case No. IPC-E-04-15
IL	North Shore Gas	Gas	2008-open	**RPC Freeze**
				Case 07-0241
IL	Peoples Gas Light & Coke	Gas	2008-open	**RPC Freeze**
				Case 07-0242
IN	Citizens Gas	Gas	2007-2011	**RPC Freeze**
				Cause No. 42767
IN	Vectren Energy	Gas	2007-open	**RPC Freeze**
				Cause No. 43046
IN	Vectren Southern Indiana	Gas & Elec	2007-open	**RPC Freeze**
				Cause No. 43046
MD	Baltimore Gas & Electric	Gas	1998-open	**RPC Freeze**
				Case No. 8780

Jurisdiction	Company Name	Services	Years in Place	Description of Revenue Adjustment Mechanism
MD	Delmarva Power & Light	Electric	2007-open	**RPC Freeze**
				Order No. 81518
MD	Potomac Electric Power	Electric	2007-open	**RPC Freeze**
				Order No. 81517
MD	Washington Gas Light	Gas	2005-2008	**RPC Freeze**
				Order No. 80130
ME	Central Maine Power	Electric	1991-1993	**RPC Freeze**
				Docket No. 90-085
NC	Public Service Co of NC	Gas	2008-open	**RPC Freeze**
				Docket No. G-5, Sub 495
NC	Piedmont Natural Gas	Gas	2005-2008	**All Forecast**
				Docket G-44 Sub 15
NC	Piedmont Natural Gas	Gas	2008-open	**RPC Freeze**
				Docket No. G-9, Sub 550
NJ	New Jersey Gas Natural	Gas	2007-2010	**RPC Freeze**
				Docket GR05121020
NJ	South Jersey Gas	Gas	2007-2010	**RPC Freeze**
				Docket GR05121019
NY	National Fuel Gas	Gas	2008-open	**RPC Freeze** NFG is allowed to recover the allowed margin on average weather normalized usage per customer for the small volume customer classes. A forward test year of 2008 is brought forth but no forecasts behind this test year
				Case 07-G-0141
OH	Vectren Energy	Gas	2007-2009	**RPC Freeze**
				Case 05-1444-GA-UNC
OR	Cascade Natural Gas	Gas	2006-2010	**RPC Freeze**
				Order No. 06-191
OR	Northwest Natural Gas	Gas	2002-2006	**RPC Freeze**
				Order No. 02-634
OR	Northwest Natural Gas	Gas	2006-2009	**RPC Freeze**
				Order No. 05-934
OR	Northwest Natural Gas	Gas	2009-2012	**RPC Freeze**
				Order No. 07-426
UT	Questar Gas	Gas	2006-2010	**RPC Freeze**
				Docket No. 05-057-T01
VA	Virginia Natural Gas	Gas	2009-2012	**RPC Freeze**
				Case No. PUE-2008-00060
WA	Avista	Gas	2007-2009	**RPC Freeze**
				Docket UG-060518
WA	Cascade Natural Gas	Gas	2005-2010	**RPC Freeze**
				Docket UG-060256

Jurisdiction	Company Name	Services	Years in Place	Description of Revenue Adjustment Mechanism
WA	Puget Sound & Power	Electric	1991-1995	**RPC Freeze**
				Docket UE-901184-P
WI	Wisconsin Public Service	Electric & Gas	2009-2012	**RPC Freeze** Applies to residential and commercial classes. Electric and Gas treated separately. Subject to a rate adjustment cap approximately equivalent to 100 basis points or $12 million for electric operation and $4 million for natural gas operation. Order also reduced the customer charges in order to encourage consumers to conserve
				Docket 6690-UR-119

Table 3

APPROVED PRECEDENTS FOR STRAIGHT-FIXED VARIABLE RATES

Jurisdiction	Company Name	Services	Years in Place	Description of SFV Rate Design
GA	Atlanta Gas Light	Gas Distribution	1999-open	Applies to all rate classes; Residential Customer charge $9.05/mo (same charge as before rate redesign implemented), metering charge $0.71/month, Annual Capacity charge $68.28/Dth, Peaking charge $11.28/Dth (applies only to customers in the Atlanta, Macon, and Valdosta delivery groups)
				Docket No. 8390-U
MO	Atmos Energy	Gas Distribution	2007-open	Applies to residential and small general service classes only; Before decision, customer charges ranged from $7.00/month to $9.05/month across territory (multiple districts) and volumetric rates ranging between $0 07495/ccf and $0.31920/ccf Customer charges increased in a range of $13.92/month to $20.61/month (multiple districts) with no volumetric charge for delivery.
				Case GR-2006-0387
MO	Missouri Gas Energy	Gas Distribution	2007-open	Applies to residential customers only. Before decision, customer charge $11.65/month with a volumetric rate of $0 13187/ccf. As a result of SFV, customer charge became $24.62/month with no volumetric charge for delivery.
				Case GR-2006-0422
MO	Laclede Gas Company	Gas Distribution	2002-open	Applies to all classes; Differentiates billing between summer and winter; Residential customer charge $12 00/month with summer volumetric charges of $0.16527/therm for the first 65 therms used per month and $0.12462/therm for all therms over 65 therms per month used and winter volumetric charges of $0.39133/therm for the first 65 therms used per month and $0.000 for any additional therms per month.
				Case GR-2006-0422
ND	Xcel Energy	Gas Distribution	2005-open	Applies to residential customers only, Before decision, Customer charge $5.50/month, volumetric charge $0.12480/therm. After decision, customer charge of $15 69/month and no volumetric charge.
				Case PU-04-578
OH	Duke Energy Ohio (CG&E)	Gas Distribution	2008-open	Applies to residential customers only; Original customer charge $6/month with a volumetric rate of $0.18591/ccf; Through September 2008, Customer Charge of $15/month, volumetric charge to cover remainder of fixed and volumetric costs; Through May 2009, Customer charge of $20.25/month, volumetric charges reduced to meet remainder of fixed and volumetric costs. Beyond that, Customer charge of $25.33/month, volumetric charge of $0.040828/ccf for the first 400 ccf and $0.105378/ccf above 400 ccf
				Case 07-590-GA-ALT
OH	Dominion East Ohio	Gas Distribution	2008-2010	Modified Straight Fixed Variable Rates; Applies to small general service customers; Two year phase in: Year 1 Customer charge $12.50/month with a volumetric charge of $0.648/mcf for the first 50 mcf and $1.075/mcf over 50 mcf. Year 2 Customer charge $15.40/month with a volumetric charge of $0.378/mcf for the first 50 mcf and $0.627/mcf over 50 mcf. Previous Customer Charge $5.70/month and previous volumetric charge $1.1201/mcf.
				Case 07-830-GA-ALT
OH	Columbia Gas	Gas Distribution	2008-open	Applies to small general service customers only (residential). Before decision Customer charge $6.50/month and volumetric charge of $1.3669/ccf Two year phase in of SFV rates: Year 1 Customer charge $12.16/month and volumetric charge of $0.7911 per Mcf, Year 2 Customer charge $17.81/month with no volumetric charge.
				Case 08-0072-GA-AIR
OH	Vectren Energy Delivery of Ohio	Gas Distribution	2009-open	Applies to residential customers only. Before decision $7.00/month customer charge, $0.11986/ccf for the first 50 ccf, $0 10442/ccf over 50 ccf Two year phase in of SFV rates: Year 1 Customer charge $13.37/month, volumetric rate of $0.07451/ccf. Year 2 $18 37/month customer charge, no volumetric rate.
				Case 07-1080-GA-AIR

Despite a generally positive experience with ERAMs, the CPUC suspended the program in the mid 1990s due to complications posed by the statutory rate freeze that accompanied retail competition. All four of these utilities have subsequently returned to decoupling and operate under decoupling today. The return to decoupling was spurred in 2001 by state legislation and the slowdown in volume growth that the California power crisis triggered.[11] Support for decoupling has been widespread in the regulatory community over the decades.

RAM Design

To understand the kinds of RAMs used in California it is helpful to understand some other characteristics of California energy utility regulation. Consider first that the CPUC has jurisdiction over an energy utility industry that in North America is second in size only to that the Federal Energy Regulatory Commission. This gives them a strong incentive to contain regulatory cost. Rate Case Plans have been an important means of realizing economies in the regulatory process. The CPUC instituted a Regulatory Lag Plan providing for a two year minimum interval between general rate cases (GRCs). A two year plan was approved for SCE in 1980. The standard lag between rate cases was increased to three years in 1984. This schedule came to be called the GRC "cycle". Plans of longer duration have since been approved on several occasions. Rate cases were staggered to reduce the chance that the CPUC had to consider cases for multiple major utilities simultaneously.

California utilities are subject to the risk of financial attrition to the extent that rates in the out years of the cycle do not reflect changes in business conditions that affect their earnings. When decoupling is in effect, the primary risk is that the revenue requirement does not adjust to reflect changes in business conditions that affect their cost. In other words, revenue decoupling in California involves multiyear revenue cap plans

Consider, next, that the CPUC has over the years established a number of policies that increase utility operating risk. Inverted block residential rate designs have been mandated since the 1970s to encourage conservation. These magnified the sensitivity of earnings to volume fluctuations and the impact of DSM. All three of the larger utilities invested in nuclear power

[11] The California legislature mandated a return to decoupling in April 2001. See California Public Utilities SEC.10. Section 739.10 as amended by Assembly Bill X1 29 (Kehoe). It provides that "The Commission shall ensure that errors in estimates of demand elasticity or sales to not result in material under or overcollections of the electrical corporations."

plants but were denied permission to fund their (often delayed) construction using the ratebasing of construction work in progress. Large scale purchases of power from non-utility generators were encouraged.

These circumstances help to explain the CPUC's willingness to provide automatic attrition relief for changes in a wide range of business conditions in the out years of the GRC cycle. The out years of the cycle came to be called the attrition years. The attrition relief mechanism was sometimes called an Attrition Relief Adjustment (ARA) mechanism. When revenue decoupling is in effect, RAMs do much of the work of providing automatic attrition relief.

Multi-year rate plans were first instituted in an era of rapid input price inflation that created a material risk of financial attrition. The CPUC early on acknowledged the need for some relief from inflation in attrition years. This was initially attempted through fixed "stepped rate" increases in the revenue requirement, as in D. 92497 for Southern California Gas (1980) and D. 92549 (1980) for SCE. However, in the early 1980's inflation greatly exceeded forecasts at a time when utilities faced other financial burdens and the Commission recognized the reasonableness of real-time inflation adjustments using indexes. In its first ERAM decision, the CPUC approved the use of a formulaic inflation adjustments using indexes, stating that

> While we would normally not be receptive to the use of an indexing mechanism under normal conditions, we find that such a mechanism is essential at this time to enable PG&E a reasonable opportunity to earn the authorized rate of return and also protect ratepayers from possible overestimates of expenses. Our experience in the past two years has clearly shown that in times of rampant inflation and unstable interest costs, it is impossible to make reasonable estimates of costs 12 to 18 months in the future.

Most subsequent California RAMs have provided inflation relief and the RPC freeze approach to RAM design has to our knowledge never been used.

Three other aspects of California regulation have also had an influence on RAM design.

- The CPUC decided in Decision 89-01-040 to address the rate of return issues of all energy utilities in separate annual proceedings. This meant that the revenue requirements generated by RAMs have often been subject to supplemental rate of return adjustments.

- Cost allocation and rate design issues are commonly addressed in Phase II of a general rate case. In attrition years, utilities have opportunities to adjust cost allocations and rate designs in rate design "windows". Any attrition relief adjustment that is occasioned by RAM operation is then pooled with certain other revenue requirement adjustments and recovered in advice letter filings using the Phase II cost allocations as amended by changes effected in the rate design windows.
- Over the long history of decoupling in California RAMs have sometimes been required to fund sizable upticks in capital spending. This is due partly to the fact that California electric utilities are vertically integrated. Even in the aftermath of the state's power industry restructuring, utilities have retained ownership of extensive nuclear and hydroelectric power generation capacity. There is greater need for occasional major plant additions in the power generation sector. Capital spending surges also occur occasionally in power distribution. Since capital spending surges are difficult to accommodate in formulaic RAMs, hybrid and stairstep RAMs have been more popular. Several plans have permitted separate treatment of discrete major plant additions such as those for power plants.

A variety of approaches to RAM design have been used in California since the inception of decoupling. The hybrid approach has been most common over the years. The broad outline of the first ERAM for PG&E was remarkably similar to that of the RAM used by SCE today.

- O&M expenses were escalated only for inflation. The CPUC implicitly acknowledged that output and productivity growth are also germane considerations in escalating these costs when it stated that "Our labor and nonlabor costs adopted for test year 1982 will be escalated by appropriate inflation factors for labor and nonlabor expenses…We will not adopt a growth factor but assume that any growth or increase in activity levels will be offset by increased productivity and efficiency." Forecasts prepared by Data Resources Incorporated (d/b/a Global Insight) of inflation in macroeconomic price indexes were used as the escalators.

- Capital spending per customer was fixed in constant dollars at a five year average of net plant additions, then escalated for inflation.
- Other components of the cost of capital, such as depreciation and the return on rate base, were forecasted using cost of service methods.

Subsequent RAMs have involved variations on this basic theme.

- Capex budgets have occasionally been fixed in real terms at the value for the (forward) test year, then escalated for construction cost inflation.
- Global Insight indexes of O&M input price inflation have replaced indexes of macroeconomic price inflation in the escalation of O&M expenses.
- O&M expenses have occasionally been escalated using the full indexation method, with a formula containing explicit provisions for inflation, productivity, and customer growth.
- The rate of return is now subject to annual resets in separate proceedings that have become increasingly formulaic. Sempra's MICAM mechanism was the first to feature formulaic adjustments.
- Funding for major plant additions has often been addressed separately.

Despite the popularity of hybrid RAMs, all of the other established approaches to RAM design save the RPC freeze have been used several times in California. The all forecast approach to RAM design was employed in some of the earliest RAMs, as previously noted. It has experienced a renaissance in the current plans for PG&E, SDG&E, and SCG. The inflation only approach to RAM design was first used in an early PG&E RAM for its gas services. It has also been used in recently expired plans for PG&E, SDG&E, and SCG. The full indexing approach to RAM design has been used in decoupling plans for SCG and SCE.

Operating Record

Eto, Stoft, and Belden report results of research on the first decade of California ERAM experience.[12] The focus is on the three largest utilities: PG&E, SCE, and SDG&E. Here are some key results

- From 1983 to 1992, the earnings of these companies tended to fluctuate in a narrow range around their allowed rates of return. The actual ROE exceeded the allowed ROE by about 15 basis points on average.
- The clearing of ERAM balances accounted for only a small portion of the total change in revenue requirements.
- The ERAMs had little impact on rate volatility. For PG&E, rate volatility was actually reduced.

As for the impact that decoupling has had on DSM, consider first that California has long ranked as a national leader in the area of DSM. There is some evidence that this DSM effort was due in part to revenue decoupling.

- Electric utilities have played a central role in the administration of California DSM programs. They have amongst the highest ratios of energy efficiency program costs to utility revenues in the industry[13]. Residential rates have an inverted block design. In 2006, for instance, the residential volumetric electric charges of PG&E were 11 cents for baseline usage, 22 cents for volumes ranging from 131% to 200% of baseline, and 35 cents for volumes exceeding 300% of the baseline.[14] PG&E's rates for residential gas service also have an inverted block design.

- Table 4 and Figure 2 show that the growth in California's utility power sales per capita has been much slower than the nation's since the middle 1970's. The divergence began before the institution of decoupling. However, it is likely due in part to inverted block rates and this is the kind of DSM measure that in other states

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[12] Joseph Eto, Steven Stoft, and Timothy Belden, *op cit.*

[13] Dan York and Martin Kushler, *A Nationwide Assessment of Utility Sector Energy Efficiency Spending, Savings, and Integration with Utility System Resource Acquisition,* Washington DC, 2006, American Council for an Energy Efficient Economy.

[14] Roland Riser, *Decoupling in California: More Than Two Decades of Broad Support and Success.* Presentation to the Workshop on Aligning Regulatory Incentives with Demand-Side Resources, San Francisco, 2006.

Table 4

Deliveries per Capita by US Electric Utilities

Year	Population[1]			Power Deliveries[2]			Deliveries per Capita[3]		
	US	California	Hawaii	US	California	Hawaii	US	California	Hawaii
1960	180.671.158	15,717.000	633,000	688,075	57,270	1.285	3,808	3,644	2,030
1961	183,691.481	16,497.000	659,000	721,950	62,386	1.554	3,930	3.782	2.358
1962	186,537,737	17,072.000	684,000	777,600	64.910	1,820	4,169	3.802	2,661
1963	189,241,798	17,668,000	682,000	832,613	69.530	2,080	4.400	3,935	3,049
1964	191,888,791	18.151.000	700,000	896,059	76.988	2,286	4,670	4,242	3,266
1965	194,302,963	18,585,000	704,000	953,789	82,687	2,452	4,909	4,449	3,464
1966	196,560,338	18,858,000	710,000	1,035,145	90.913	2,642	5,266	4,821	3,721
1967	198,712,056	19,176,000	723,000	1.099,217	96.983	2,720	5,532	5,058	3,762
1968	200,706,052	19,394,000	734,000	1,202,671	104,615	3,132	5,993	5,394	4,267
1969	202,676,946	19,711,000	750.000	1,313,833	111,468	3,446	6,482	5,655	4.594
1970	205,052,174	19,971,069	769.913	1,392,300	118,645	3,776	6,790	5,941	4.905
1971	207,660,677	20,345,724	801,644	1,469,540	125,835	4,187	7,077	6,185	5.224
1972	209,896.021	20,584,918	828,331	1,595,161	135,301	4,587	7,600	6,573	5.537
1973	211,908,788	20,667,894	851,595	1,712,909	140,046	4,893	8,083	6.711	5,746
1974	213,853,928	21,172,684	867,976	1,705.924	131.443	5.144	7,977	6.208	5,927
1975	215,973,199	21,536,811	886,160	1,747,091	148,421	5,310	8,089	6,892	5,992
1976	218,035,164	21,934.604	904,191	1,855,246	156,018	5,588	8,509	7,113	6,160
1977	220,239,425	22,350,332	918,259	1,948,361	158.800	5.795	8,847	7,105	6,310
1978	222,584,545	22,839,038	931,584	2,017,922	162.647	5.958	9,068	7,121	6,396
1979	225,055,487	23,255,178	953,308	2,071,099	169,590	6,199	9,203	7,293	6,503
1980	227,224,681	23,667,902	984,691	2,094,447	167,567	6,331	9,218	7,080	6,563
1981	229,465.714	24,285,933	978.195	2.147,102	170.414	6,646	9,357	7,017	6,794
1982	231,684.458	24,620,009	993,780	2,086,440	165,843	6,497	9,006	6,682	6,538
1983	233,791,994	25,360,026	1,012,717	2,150,955	165,199	6,581	9,200	6,514	6,498
1984	235,824,902	25,844,393	1,027,922	2,285,796	179,453	6,605	9,693	6,944	6,426
1985	237,923,795	26,441,109	1,039,698	2,323,974	184,331	6,635	9,768	6,971	6,381
1986	240,132,887	27,102,237	1,051,762	2,368,753	185,419	7,032	9,864	6,841	6,686
1987	242,288,918	27,777,158	1,067,918	2,457,272	192,800	7,298	10,142	6,941	6,834
1988	244,498,982	28,464,249	1,079,828	2,578,063	200,637	7,719	10,544	7,049	7,148
1989	246,819,230	29,218,164	1,094,588	2,646,809	204,139	7,970	10,724	6,987	7,282
1990	249,464,396	29,760,021	1,108,229	2,712,555	211,093	8,311	10,874	7,093	7,499
1991	252,153,092	30,414,114	1,131,412	2,762,003	208,650	8,524	10,854	6,860	7,534
1992	255,029,699	30,875,920	1,149,926	2,763,365	213,447	8,667	10,835	6,913	7,537
1993	257,782,608	31,147,208	1,161,508	2,861,462	210,500	8,658	11,100	6,758	7,454
1994	260,327,021	31,317,179	1,173,903	2,934,563	213,684	8,948	11,273	6,823	7,623
1995	262,803,276	31,493,525	1,180,490	3,013,287	212,605	9,188	11,466	6,751	7,783
1996	265,228,572	31,780,829	1,184,434	3,101,127	218,112	9,379	11,692	6,863	7,919
1997	267,783,607	32,217,708	1,189,322	3,145,610	227,880	9,363	11,747	7,073	7,873
1998	270,248,003	32,682,794	1,190,472	3,264,231	236,434	9,261	12,079	7,234	7,779
1999	272,690,813	33,145,121	1,185,497	3,312,087	234,831	9,381	12,146	7,085	7,913
2000	281,421,906	33,871,648	1,211,537	3,421,414	244,057	9,691	12,158	7,205	7,998
2001	285,039,803	34,507,030	1,218,553	3,394,458	247,759	9,765	11,909	7,180	8,030
2002	287,726,647	34,916,495	1,228,763	3,465,468	235,213	9,892	12,044	6,736	8,050
2003	290,210,914	35,307,398	1,240,325	3,493,841	243,221	10,391	12,039	6,889	8,378
2004	292,892,127	35,629,666	1,254,172	3,547,519	252,026	10,732	12,112	7,073	8,557
2005	295,560,549	35,885,415	1,267,581	3,661,007	254,250	10,539	12,387	7,085	8,314
2006	298,362,973	36,121,296	1,276,635	3,869,963	262,959	10,568	12,300	7,280	8,265
Average Annual Growth Rates									
1960-2006	1.09%	1.61%	1.53%	3.64%	3.31%	4.58%	2.55%	1.50%	3.05%
1960-1970	1.27%	2.40%	1.96%	7.05%	7.28%	10.78%	5.78%	4.89%	8.82%
1970-1980	1.03%	1.70%	2.26%	4.08%	3.45%	5.17%	3.06%	1.75%	2.91%
1980-2000	1.07%	1.79%	1.14%	2.45%	1.88%	2.13%	1.38%	0.09%	0.99%

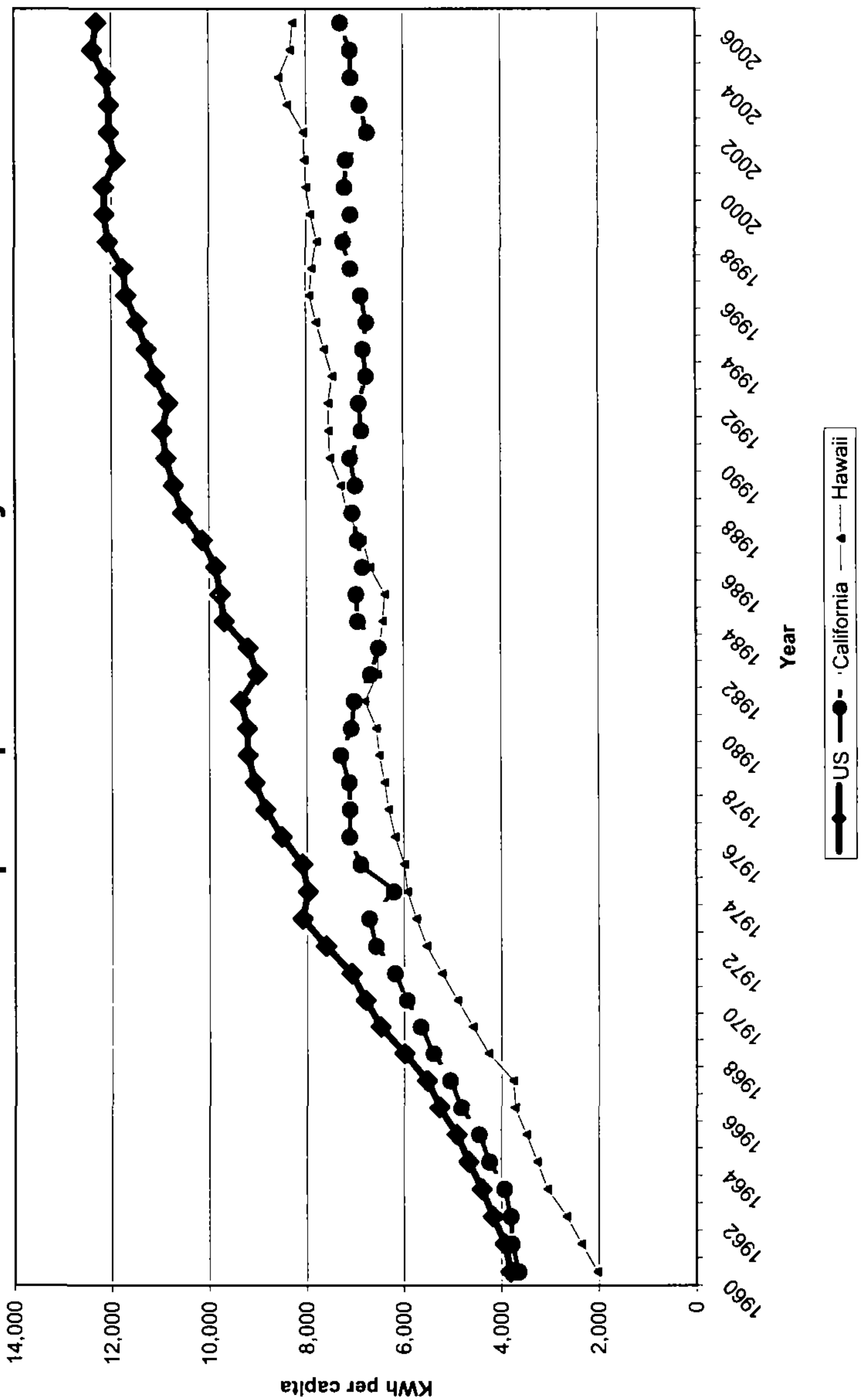
[1] Source US Census Bureau

[2] Source Energy Information Administration Form EIA-826 for 1960 to 1983 and form EIA-861 for 1984 to present (Sales of Electricity to Ultimate Consumer) Units are Million Kilowatthours.

[3] This is calculated by dividing the volumes by the population values

Figure 2

Annual per Capita Electricity Deliveries



(including Hawaii) would be encouraged by decoupling.

- Energy efficiency spending by California electric utilities dropped in the mid-1990s, when ERAMs were suspended. Spending has rebounded substantially since the resumption of decoupling[15].

- Energy efficiency savings achieved by these same utilities fell substantially in the mid-1990s after the suspension of ERAMs. Following the resumption of decoupling, savings rebound substantially in 2004[16].

On the other hand, decoupling in California was part of a package of utility incentives that also included compensation for DSM spending and rewards for good performance. Moreover, state policies in California have also played a prominent role in encouraging conservation (and solar power). For example, the CPUCs 2005 "Energy Action Plan" made energy efficiency the first resource in the utility loading order. These realities make it difficult to measure the specific contribution of decoupling to the progress of DSM.

Given the difficulty of identifying the specific impact of decoupling, it is understandable that Kushler, York, and Witte conclude their review of California decouplings' impact by stating that the state's decoupling plans are

> one element of a much larger energy policy – a policy that requires utilities to commit large amounts of resources to fund and implement energy efficiency programs. We found no efforts to date that attempt to evaluate the impacts of just the decoupling mechanisms on the utilities' investment and related actions towards energy efficiency programs. Given these tremendous additional changes with CPUC targets and approved budgets for energy efficiency programs, we believe that it is difficult to isolate the specific policy impacts of decoupling. However, we also observe that establishing such mechanisms is a valuable complement to achieving the overall

[15] Charles J. Cicchetti, *A Primary for Energy Efficiency: Going Green and Getting it Right*, Washington DC, PUR 2009, p. 238.

[16] Charles J. Cicchetti, *op cit.* p. 239.

policy objective. It's part of a "complete package" to align utility financial interests with public policy interests towards greater levels of energy efficiency."[17]

3.1.2 Other Jurisdictions

The Spread of Decoupling

Precedents for the true up approach to revenue decoupling outside California are also listed in Table 2. It can be seen that decoupling was adopted to regulate electric utilities in Maine, New York, and Washington state in the early 1990s. The early innovators included Orange & Rockland Utilities, Niagara Mohawk Power, Consolidated Edison, Puget Power, & Central Maine Power.

Kushler, York, and Witte discuss the impact of the decoupling mechanism in Washington[18]. They state that "Implementation of this decoupling mechanism played a critical part in changing the role of energy efficiency and conservation programs within Puget Sound Energy. In the first two years there were dramatic improvements in energy efficiency program performance." In extending the program for another three years in 1993, the WUTC observed that the decoupling mechanism "has achieved its primary goal – the removal of disincentives to conservation investment. Puget has developed a distinguished reputation because of its conservation programs and is now a national leader in this area."[19]

Decoupling was suspended after a few years in all of these states. In New York, this was due in part to the move towards power industry restructuring. In Maine, suspension of decoupling reflected its role in raising rates during a recession. In Washington, a rise in rates was also a key concern but resulted from a rise in power supply costs.

Decoupling in the electric power industry resumed in Oregon in 1998 in an application to the distribution function of Pacificorp. In 2007, it was adopted for electric utilities in Idaho (Idaho Power) and Maryland (Delmarva Power and Light and Potomac Electric Power). In late 2009, decoupling was approved for the electric as well as the gas services of Wisconsin Public

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[17] Martin Kushler, Dan York, and Patti Witte *op cit.* pp. 46-50.

[18] Martin Kushler, Dan York, and Patti Witte, *Aligning Utility Interests with Energy Efficiency Objectives: A Review of Recent Efforts at Decoupling and Performance Incentives"*, Report Number U061, American Council for an Energy-Efficient Economy, Washington DC, 2006. p. 40.

[19] WUTC, 11th Supplemental Order, Sept. 21 1993.

Service. Recent generic proceedings in Massachusetts and New York have lead regulators in each state to require that energy utilities implement decoupling. Several utilities have resumed decoupling in New York. State law provides that decoupling in some form be implemented prospectively in Connecticut. Utilities in Michigan (Consumers Energy and Detroit Edison) and Wisconsin (Wisconsin Power & Light) were recently directed to file decoupling plans.

Table 2 also shows that use of decoupling today is much more widespread in the regulation of local gas distribution companies (LDCs). Many LDCs have been experiencing declines in the average use of gas by residential and commercial customers. These declines reflect, in the main, external market developments rather than aggressive DSM programs. These developments have included marked improvements in gas appliance efficiency and recent run-ups in gas commodity prices.

Given typical rate designs, which feature volumetric charges well above short run marginal cost, LDCs faced with this problem will, absent decoupling, come in for rate cases frequently over a recurrent set of issues. Decoupling provides automatic relief for declining average use and permits LDCs to come in for rate cases less frequently. Some LDCs that operate under decoupling do not have active DSM programs. Due in part to the greater sensitivity of larger volume gas users to the terms of service, the decoupling plans of many gas LDCs apply only to residential and commercial customers.

A decoupling plan approved for Northwest Natural Gas in 2002 was the subject of a positive independent review. Here are some key findings.

- The Energy Trust of Oregon reported that Northwest Natural developed a good working relationship and its efforts to promote energy efficiency complemented its own efforts.
- HVAC distributors reported that the company's marketing efforts helped increase sales of high efficiency furnaces. Oregon achieved the highest share of high efficiency furnaces in new furnace sales in the nation.
- There was little shifting of risk to customers.
- Perhaps because of the plan's service quality provisions, there was no attenuation of quality incentives.

The reviewers recommended a continuation of decoupling and a new program commenced in 2006.

In totality, the following 17 states and two Canadian provinces have tried the true-up approach to decoupling for one or more gas or electric utilities.

US: CA, CO, ID, IL, IN, FL, MD, ME, NC, NJ, NY, OH, OR, UT, VT, WA, WI

Canada: ONT, BC

Most states that have tried the true up approach have active decoupling plans. Several (*e.g.* CA, BC, and NC) have renewed them. Only one state (Maine) has suspended decoupling and not later resumed it.

SFV pricing has been used on a large scale by the Federal Energy Regulatory Commission since the early 1990s to regulate natural gas pipelines. In that application, lower volumetric charges coincided with higher capacity charges. This ultimately raised the share of system cost collected from winter space heating users of gas. The goal was not to discourage system use and delivery volumes grew, especially for power generation.

Precedents for the use of SFV in retail ratemaking are reported in Table 3. It can be seen that its use has to date been confined to the gas distribution industry, where it has been adopted in Georgia, Missouri, North Dakota, and Ohio. Ohio is noteworthy for having recently switched from the trueup approach to decoupling to the SFV approach. Commissions in Connecticut and Delaware have recently indicated a preference for SFV. In addition, several states have in recent years made noteworthy steps in the direction of SFV by redesigning LDC rates to obtain less revenue from volumetric charges.

Note, finally, that at least six additional states to our knowledge are actively considering some form of decoupling. These include, in addition to Hawaii, Kansas, Minnesota, Nevada, New Hampshire, and Rhode Island.[20] Additional impetus to consider restructuring may come from changes in federal energy policy, including the economic stimulus legislation that is currently under consideration in Congress.

Approaches to RAM Design

Regarding the popular forms of RAM design, Table 2 shows that the RPC freeze approach was first employed by Puget Sound and Central Maine Power in the early 1990s. Both plans pertained to the total revenue per customer. To avoid gaming opportunities regarding the measurement of customer numbers, Washington and Maine adopted detailed written definitions

[20] Decoupling is required under state law in Connecticut but has not yet been implemented.

and procedures for counting and verification of customers. RPC freezes are currently used by many utilities outside California. Most are gas utilities, but this approach has also recently been adopted by electric utilities in Idaho, Maryland, and Wisconsin. Decoupling is often applied only to smaller-volume customers.

PEG has interviewed the staff of several utilities operating under RPC freezes in our research for HECO. All of the respondents indicated that they did not expect these mechanisms to provide full attrition relief. All retained the right to file rate cases and several of the utilities that we contacted have done so. For example, Idaho Power came in for a rate case in 2008, the second year of its decoupling plan. The fact that RPC freezes apply chiefly to gas LDCs makes sense since, for these utilities, such freezes will reduce the financial attrition that results from declining average use by residential and commercial customers. RPC freezes are also handy in providing a ready basis for adjusting the revenue requirements of specific customer classes.

As for the other approaches to RAM design, all-forecast RAMs have been the norm over the years in New York. However, a hybrid RAM has been used in New York and for Vermont Gas Systems. In New York, all forecast RAMS have been facilitated by a forward test year tradition and a longstanding commission to the use of formulaic rate and revenue caps. A three year rate case cycle has been common. Full indexation is used in the current RAM of Toronto-based Enbridge Gas Distribution, Canada's largest gas company. Hybrid RAMs have been used to regulate power distributors in the populous state of New South Wales, Australia.

Impact on Conservation

As for the impact of decoupling in other states, comparatively few have had decoupling for electric utilities, as we have seen. Many states that are recognized as electricity DSM leaders (e.g. Connecticut, Minnesota, New Jersey, and Wisconsin) have not to date been decoupling leaders. All of these states permitted recovery of DSM costs and several offered DSM performance incentives. It follows that the impact of decoupling cannot be gleaned from casual empiricism.

Dr. Charles Cicchetti, a fellow partner of Pacific Economics Group, is in the process of publishing a book that reports results of statistical research on the determinants of DSM spending and DSM savings[21]. The study uses U.S. Energy Information Administration data on incremental energy savings and spending by 200 large electric utilities from 1992 to 2006. Econometric research was used to identify multiple determinants for each variable. Cicchetti found that, after controlling for the other identified business conditions, revenue decoupling had an impact on energy savings that was statistically significant at a high level of confidence. Decoupling was also found to have a significant positive impact on energy efficiency savings.

3.1.3 Observations

Based on this review, we may conclude that the use of revenue decoupling in North American regulation of energy utilities is widespread and growing. Decoupling is a part of a package of incentives that can induce electric utilities to aggressively promote DSM. Decoupling is, additionally, a common response to the financial challenge of declining average sales even where utilities are not engaged in aggressive DSM programs. Given its popularity in the gas industry, we may also conclude that decoupling will be an increasingly common response to material declines in the volume per customer of *electric* utilities such as may result in the future from slower economic growth and increased power conservation efforts at the state and federal level.

As for approaches to RAM design we conclude that, despite the popularity of RPC freezes in the gas industry, the great majority of RAMs that have been approved around the world and over time are designed to provide automatic attrition relief for inflation as well as customer growth. All forecast and hybrid RAMs have been the principle means of providing such relief. Their popularity may be attributed to the flexibility with which they can provide relief for inflation and customer growth, under a variety of operating conditions, without complex indexing research

[21] Charles J. Cicchetti, *op cit.*

4. Decoupling Pros and Cons

The regulatory literature, the many proceedings in which decoupling have been discussed, and the accumulating experience with decoupling plans have generated a great deal of discussion concerning the advantages and disadvantages of decoupling. We provide here some highlights.

4.1 Benefits of Decoupling

Promotion of DSM and DG

Decoupling eliminates one of the main disincentives that utilities currently have to facilitate DSM, customer-sited DG, and distributed energy storage. If effective DSM and renewable DG are thereby promoted, customer bills will be lowered, construction of new generation capacity will be slowed, and the power industry will have a less damaging impact on the environment. To the extent that power is currently generated using petroleum products, DSM and renewable DG also promote price stability and reduce our nation's dependency on oil imports. Non-renewable forms of DG can also have benefits, such as reduced need for new generation capacity and better local grid operation and reliability.

It is widely acknowledged that decoupling cannot, by solving the "lost revenue" problem, by itself induce utilities to be aggressive proponents of DSM and DG. Most notably, utilities need compensation for the cost of their DSM and DG initiatives. Incentives to encourage efficient work are also desirable.

Some argue that a utility operating under decoupling still retains a long term incentive for sales volume growth to the extent that such growth may ultimately require plant additions. This is not a major problem for energy distributors since plant additions are not driven chiefly by volume growth. For vertically integrated electric utilities, however, volume growth creates opportunities for new generation investment. The incentive problem can be mitigated by competitive bidding for new generation or forms of compensation for utility DSM and DG programs that are linked to avoiding capacity additions.

The incentive effects of decoupling are reduced to the extent that programs to promote DSM and DG services are undertaken by independent agencies rather than utilities. Such agencies have been established in Connecticut, Maine, New Jersey, New York, Ohio, Oregon, Vermont and Wisconsin in addition to Hawaii. However, utilities in their capacity as tariff administrators and managers of the power system have special advantages in the use of rate design and direct load control programs to manage demand. As a consequence, they continue to play a prominent role in these areas even where some energy efficiency programs are undertaken by other agencies. For example, inverted block rates are one of the most cost effective tools for reducing power consumption and mitigating the environmental damage caused by power systems. Time of use pricing can, similarly, play a key role in avoiding needless capacity additions. The ability of utilities to assist with demand response is aided by the use of automated metering technology.

There are many other ways that utilities can help to encourage DG and DSM when energy efficiency programs are independently administered. Here are some noteworthy examples.

- Advertising that promotes DG and DSM
- Research and development on promising approaches to DG and DSM
- Support of state legislation and administrative policies that encourage DG and DSM
    - ✓ Appliance efficiency standards
    - ✓ Building codes
    - ✓ Tax credits for DG and DSM investments
    - ✓ Renewable portfolio standards
- Direct promotion of DG, which may not be a focus of independent programs
    - ✓ Promotional programs
    - ✓ Net metering

  - ✓ Feed-in tariffs
  - ✓ Interconnections policy
- Miscellaneous investments in the capacity to accommodate the variable flows of power from renewable sources

Attrition Relief

Many other benefits of decoupling stem from its ability to afford energy utilities relief from the financial attrition that may otherwise result from declines in sales per customer. Secular declines in electricity sales per customer can, as we have seen, result from a wide variety of circumstances that include aggressive conservation programs, sustained high prices of bulk power and/or generation fuels, changes in appliance efficiency standards and photovoltaic ("PV") and other forms of distributed generation ("DG"). Decoupling makes utilities whole for such declines. In so doing, it promotes just and reasonable compensation for a legitimate financial challenge --- a matter of fairness --- and reduces the risk of undercompensation that might otherwise result.

Full decoupling has the added benefit of stabilizing revenue in the face of volume fluctuations that result, in the short run, from changes in weather and local economic conditions. This also reduces risk. The importance of mitigating this form of risk is greatly magnified when the utility is using inverted block rates to encourage conservation.

The reduced risk of sales fluctuations and a more secular decline in average sales can lower the cost of obtaining funds in capital markets and this benefit can be shared with customers. However, the implementation of decoupling will not necessarily coincide with a lower allowed rate of return. To the extent that declining average sales is an emerging problem, for instance, the existing rate of return may not reflect the risk. The existing rate of return target may also fail to properly reflect other emerging risks. A utility expecting major growth in renewable energy resources, for instance, confronts many kinds of operating challenges that could result in unforeseen and controversial costs. Operation under a RAM for several years without rate cases involves other kinds of cost recovery risk.

More Efficient Regulation

Automatic compensation for fluctuations and secular declines in average sales can have supplemental benefits. One is an increase in the efficiency of regulation.

- The frequency of rate cases can be reduced since an important source of financial attrition is being addressed by other means.
- Decoupling reduces the importance of load forecasts in rate setting. This is a subject of considerable controversy in many proceedings.
- Decoupling also reduces the importance in regulation of the calculations that are required to accurately estimate the load impact of utility DSM programs. These play a much larger role in regulation under the alternative lost revenue adjustment approach to the reimbursement of utility DSM programs. Lost revenue calculations are difficult to determine accurately in a world where many economic conditions, including appliance standards, building codes, and high energy prices, can encourage the slowdown of volume growth. The Washington Utilities and Transportation Commission stated in its 1991 approval of a decoupling mechanism for Puget Sound Energy that "the Commission believes that a mechanism that attempts to identify and correct only for sales reductions associated with company-sponsored conservation programs may be unduly difficult to implement and monitor". Note also that the dollars at stake can become quite large as DSM effects accumulate.
- The improvement in the efficiency of regulation can be furthered to the extent that RAMs provide relief for a broad range of attrition challenges since these permit a further extension of the period between rate cases.

The benefits of regulatory efficiency can be manifested in several ways. Regulatory cost may be reduced. Alternatively, cost savings may permit a redirection of regulatory resources to improve regulation in other areas. Such economies are especially useful in a period of rapid change, when a host of new regulatory issues may arise.

Better Cost Management

Reducing the frequency of rate cases also strengthens a utility's incentives to contain cost, and managers have more time for cost management. For vertically integrated electric utilities, the tools for better cost management include time of use pricing to slow the need for capacity additions. Cost performance should improve leading, in the long run, to lower rates for customers. The benefits of better cost management can be enhanced with RAMs that provide relief for a broad range of attrition challenges since these permit a further extension of the period between rate cases.

4.2 Arguments Against Decoupling

The lively debate on decoupling has also included some criticisms. We address here some arguments that were not implicitly addressed in Section 3.2.1.

A common complaint with decoupling is that it compensates utilities for normal demand-side business risks, such as fluctuations in weather and local business activity, that they should be prepared to shoulder. However, a utility that uses inverted block rates to encourage conservation has earnings that are unusually sensitive to volume fluctuations. Any financial benefits of lower risk can, in any event, be shared with customers. It is possible, in principle, to decouple revenue only from the secular slowdown in volume growth that results from utility DG and DSM programs. However, this approach is reliant on complex calculations.

A variant on this line of criticism is that decoupling guarantees the subject utility its rate of return. This claim is invalid since decoupling does not ensure that a company's revenue requirement equals its cost. Financial attrition can still result from an unreasonably low revenue requirement, unexpectedly adverse cost conditions, or imprudent cost management. Decoupling plans reduce rate case frequency when utilities face declining average use. This spur to better cost management can be increased with well-designed multiyear RAMs.

Another common complaint about decoupling is that it increases the complexity of regulation. The true up approach to decoupling, after all, involves regular rate adjustments and the administration of a RAM. These arguments have reduced force when average sales are declining and RAMs adjust the revenue requirement automatically for multiple business conditions since the frequency of rate cases is then reduced by decoupling.

Critics also complain that decoupling destabilizes rates. This disadvantage is offset by the ability of decoupling to stabilize *bills*. For example, residential power bills under decoupling will tend to be larger in a year of unusually cool weather but will also be smaller in a year of unusually warm weather.

On the other hand, bills for a particular customer class are not stabilized to the extent that changes in the volume of deliveries to one customer class change the bills of a different class with more stable usage. An example would be an increase in residential bills due to a downturn in commercial demand.

A fourth criticism of decoupling is that it erodes incentives to offer services on market-responsive terms. While companies in competitive markets can suffer sharp reductions in business and big losses when their terms of service are not competitive, decoupling eliminates the chance (already diminished by the monopoly character of utility service) that a utility would suffer financial harm from volume losses. Quality may suffer, and customers may not be offered the special pricing packages that they need.[22] A related argument is that decoupling weakens the incentive of regulators to avoid policies that could, by reducing sales volumes, otherwise compromise utility finances.

Concern about the market responsiveness of rate and service offerings is greater to the extent that a utility serves customers whose demand is especially sensitive to the terms of service. A good example of such customers is industrial establishments that consume large amounts of power and can self generate or shift operations to other jurisdictions. Decoupling could in principle trigger cause the loss of existing large volume customers and a failure to attract new ones, to the detriment of the local economy.

The importance of bypass risk varies greatly by service territory. In economies that are highly commercialized, the risk is generally contained. It should also be noted that decoupling does not discourage real time and other forms of time of use pricing when these pricing strategies can discourage needless increases in production capacity. To the extent that there is any residual

[22] Since a utility's rates are linked to its own cost of service, its incentive for cost containment is also somewhat diminished by reduced volume risk.

concern, it can be remedied by applying decoupling selectively to residential and commercial customers and by developing service quality monitoring or incentive plans.

Yet another complaint is that decoupling may disincent utilities from encouraging uses of power that can actually further environmental and other policy goals. Salient in this regard is the use of natural gas and electricity to power motor vehicles. This problem can be sidestepped by excluding sales for electric vehicle use from the force of decoupling where these can be identified. However, this eliminates a potentially important force that can offset declines in average use and thereby mitigate the rate hikes that can otherwise be occasioned by decoupling.

The argument can also be ventured (although it is seldom made) that many electric utilities were, at least until the current recession, experiencing *increasing* average sales and not the decreasing average sales that many gas LDCs face. Under these conditions, some of the benefits afforded by decoupling when average sales decline are negated. Decoupling removes a source of automatic revenue growth and thereby *increases* financial attrition rather than reducing it. Historic test years, which are still quite common in American regulation, become less compensatory. The result can be more frequent rate cases that increase regulatory cost and weaken utility performance incentives. A counterargument to this line of attack is that decoupling will not typically be implemented for electric utilities except in situations where sales per customer are either already flat or declining or expected to do so in the future.

4.3 Observations

The growing popularity of decoupling is evidence that its introduction provides expected net benefits to the regulatory process in many situations. Our discussion of the pros and cons of decoupling helps us to identify situations in which it will be especially beneficial. Generally speaking, decoupling will be beneficial to the extent that the following conditions hold.

- State policymakers are committed to the goals of energy conservation and a cleaner environment.

- Average sales are stagnant or expected to decline due to some combination of aggressive DSM and DG programs, high energy prices, increased appliance efficiency, and slow growth of the local economy.

- The utility plays a leading role in the administration of DSM and DG programs

- Inverted block rates are recognized and encouraged as an effective DSM tool
- Demand is hard to forecast
- Power is generated by price-volatile fossil fuels such as gas or oil
- Power is generated by environmentally damaging fuels such as coal or oil
- Potential bypass customers account for a small share of load
- Incremental power supplies will be purchased rather than self-generated
- RAM design permits some reduction in the frequency of rate cases.

4.4 Implications for Hawaii

The degree to which the conditions, set forth in Section 4.3, that favor the institution of revenue decoupling currently exist in the state of Hawaii is clearly striking.

- The State of Hawaii is strongly committed to the goals of energy conservation and a cleaner environment, and ambitious DSM and DG are expected.
- Due in part to past and present DSM programs, the sales per customer growth of HECO is already slow.
- Even though conservation may be fostered by government policies and many DSM programs will be conducted by independent agencies in Hawaii, these activities will create a financial attrition problem for the HECO companies which is material.
- HECO is, in any event, expected to play an important role in DSM and DG. For example, it proposes inverted block rates for residential customers, an end to declining block rates and the institution of time of use pricing for commercial and industrial customers, investments in AMI, and various measures to encourage photovoltaic and other forms of customer-sited DG. HECO also proposes to play an extensive role in energy efficiency programs for commercial and industrial customers.

- The worldwide recession will make power sales in Hawaii's tourism-sensitive economy hard to forecast for several years.
- Power in Hawaii is currently generated primarily using petroleum products. The price of petroleum has been remarkably high in recent years and will likely rebound from current lows when the recession ends.
- The intense sunlight of Hawaii makes it a promising candidate for photovoltaic DG.
- Most incremental generation capacity in the service territories of the HECO companies is expected to be purchased. The combination of decoupling and expected power purchases should make the Companies willing partners in the promotion of DSM and DG provided that they are compensated, additionally, for prudent costs that they incur to support such initiatives. In other words, decoupling will help to align the interests of the HECO companies with those of customers, state policymakers, and DSM and DG advocates.
- Decoupling and the approach to RAM design that the HECO companies are proposing will together reduce the frequency of rate cases and simplify the regulatory process. This will prove a blessing at a time when the envisioned acceleration of DSM, DG, and renewable energy purchase programs will raise a host of other regulatory issues.

We conclude from this analysis that there are strong arguments for the approach to decoupling that the HECO companies are proposing. Decoupling can help promote the State of Hawaii's agenda of energy conservation and sound environmental stewardship while encouraging price stability and reduced reliance on foreign oil. The detailed plan of action contained in the Energy Agreement is indication of HECO's good intent, and illustrates the kind of proactive measures that decoupling helps to encourage. There are good prospects that the HECO companies will "hit the ground running" when decoupling commences.

4.5 SFV vs. Trueups

A lively debate has also developed in some jurisdictions over the relative merits of SFV and the true up approach to decoupling. We present here a distillation of some key points.

4.5.1 Rate Impacts

The true-up approach to decoupling has the special advantage, relative to SFV pricing, of permitting the use of high volumetric charges as a tool to promote DSM and DG. Proponents of SFV pricing sometimes counter that it is more important to send customers the right price signals. Volumetric charges that exceed the marginal cost of power use to society can discourage socially beneficial power use and encourage inefficient DG. However, volumetric charges based on a vertically integrated utility's *short run* marginal cost, which consists largely of line losses, may be well below its *long run* marginal cost. For example, new generation plant will eventually have to be built to replace plant that serves existing load levels. Note also that the production of power is widely considered to involve externalities that could warrant a supplemental volumetric charge in order to bring the overall charge up to the long run social marginal cost. An externality adder would be especially large when power is produced from oil-fired generation, a common practice in isolated island systems such as Hawaii's.

SFV also typically involves a substantial increase in customer charges, and these can raise bills substantially for small-volume customers. Although this type of pricing is common in other consumer businesses (*e.g.* cable television), small volume customers are often subject to special protections in utility regulation. It can also be argued that cost depends in part on peak system use and that small volume customers often make less use of the system at the peak than some larger volume customers. This problem can be ameliorated by a "sliding scale" system whereby customer charges vary in some rough fashion with historical consumption. To the extent that small customers are nonetheless adversely affected, it may be noted that this customer group can differ materially from the group of low income customers.

The problems of high bills for small customers and weak incentives for conservation may be alleviated by the addition of a revenue neutral energy efficiency adjustment ("REEF") to the SFV pricing scheme. The idea of a REEF, which is sometimes called a "feebate" system, has been championed by David Magnus Boonin, the author of the Commission's recent scoping paper. The idea is to charge a premium to each customer group for any power consumption in excess of a certain volumetric threshold. The dollars thus gathered would be transferred to customers (hence the notion of revenue neutrality) with power consumption below a certain threshold. The extra fee per dollar of excess consumption could be set so that the effective total charge per unit purchased equals an estimate of the long run marginal cost of a kWh to society.

4.5.2 Simplicity

Simple SFV has some advantages over the true up approach to decoupling in the area of simplicity. Most obviously, there is no need for periodic true ups. This simplicity advantage is offset to the extent that the true up approach involves a RAM that permits a material reduction in the frequency of rate cases. The addition of a REEF system would further erode the simplicity advantage of SFV.

4.5.3 Observations

Our discussion suggests that the SFV approach to decoupling is especially advantageous compared to the true up approach under the following conditions:

- The long run marginal cost to the utility of a unit sold is not far above the short run marginal cost. This is more likely to be true for a gas or electric power distributor than for a vertically integrated electric utility.
- The additional marginal cost of any social problems engendered by the sale of energy is small.
- The RAM is not designed to reduce the frequency of rate cases.

These conditions do not seem to hold for the HECO companies.

5. Application to the HECO Companies

In this section we discuss our research to simulate the financial impact of alternative RAMs for HECO, HELCO, and MECO over a recent historical period. Our focus is on alternative approaches to the design of hybrid RAMs. This is the methodology preferred by HECO and seems to be indicated by the terms of the Energy Agreement.

Plans of three year and four year duration were considered. The simulation period is 1996-2007. This is the most recent 12 year period for which the requisite data are available. A twelve year period was chosen because it permits consideration of four three-year periods and three four-year periods without having to arbitrarily select years during which a RAM was not in force.

Calculations of financial sufficiency compare revenues to the cost of service. We computed two financial sufficiency measures: the revenue surplus (shortfall) and a revenue/cost ratio. The sufficiency measures pertain only to the attrition years of each plan. Results are reported for an average of three and four year plans. both kinds of plans.

In the first year of each plan we set the test year revenue requirement that would hypothetically be in force equal to the actual cost of service. This is tantamount to assuming a perfect foresight outcome of the rate case.

5.1 Defining Cost

Our financial sufficiency calculations employed cost of service data provided by HECO staff. For each year of the simulation period we calculated the applicable non-energy cost of each company. This consisted of certain non-energy O&M expenses and the total capital cost. The costs of the Companies that were excluded from the analysis were those that would likely be recovered by other means in the new regulatory system: those for generation fuels, purchased power (including capacity), retirements, DSM, and integrated resource planning (IRP). Capital cost was computed using traditional cost of service methods and is the sum of depreciation, taxes, and a return on rate base. The rate of return on rate base for all companies was the target rate of return established by the Commission for HECO.

The total reference costs for HECO, HELCO, and MECO that result from these calculations are reported in Tables 5a-5c. The reported tax expenses in these tables were not the historical figures. Rather, they were estimated to be commensurate with the other listed costs and include a full return on rate base at the targeted rate of return that the Commission granted to HECO. This approach was taken because the Companies' actual taxes were depressed during many of these years by a return on equity that was well below the approved target.

Inspecting the results of Tables 5a-5c, it can be seen that the cost growth of the companies varied, being slowest for HECO and most rapid for HELCO. These results reflect in part the noteworthy differences in the pace of output growth of the companies during the simulation period. For example, the customer growth of HECO averaged 0.9% whereas those of MECO and HELCO averaged 2.0% and 2.8%, respectively. The growth trends for HELCO and MECO were well above the norms for our vertically integrated electric utility sample.

5.2 Inflation

Our discussion in Section 3 revealed that most RAMs that have been approved over time and around the word feature measures of price inflation. In this section we consider some of the measures that might be used for the HECO companies.

In California, the O&M expenses in hybrid RAMs are commonly escalated by indexes of utility O&M input price inflation. An index is typically assigned to each of several cost categories. The source of the input price indexes is Global Insight, which has for many years maintained a Utility Cost Information Service that is available by subscription. Indexes are calculated for gas utility and electric utility O&M expenses. The service includes multiyear forecasts of inflation in each index as well as historical values. Forecasts are updated quarterly and reported in a document that is currently called the *Power Planner.*

Global Insight computes price indexes for the following four categories of salaries and wages:

- Electric Power Generation, Transmission, and Distribution Workers
- Managers and Administrators
- Professional and Technical Workers

Table 5a

COST OF SERVICE CALCULATIONS

	Net O&M Expenses						Capital Costs										Total COS	
	Non-Energy, Non-Capacity																	
Year	Operation [A]	Maintenance [B]	Retirement Expense, DSM & IRP [C]	Subtotal [D]=[A]+[B]-[C]	GR*	% of Total Cost [D]/[K]	Net Depreciation + Amortization [E]	Taxes[1] [F]	GR*	Rate Base [G]	HPUC Target ROR [H]	Required Return on Rate Base [I]=[G]x[H]	GR*	Total Capital Cost [J]=[E]+[F]+[I]	GR*	% of Total [J]/[K]	Cost [K]=[D]+[J]	GR*
HECO																		
1996	94,600,203	31,756,753	20,402,283	105,954,673		47%	46,099,894	58,434,657		818,276,000	9.16%	74,954,082		179,488,632		53%	285,443,306	
1997	96,885,396	31,017,600	23,497,169	104,405,827	-1.5%	45%	50,932,392	60,901,036	4.1%	864,771,000	9.16%	79,213,024	5.5%	191,046,452	6.2%	55%	295,452,279	3.4%
1998	90,887,742	26,307,886	16,461,888	100,733,740	-3.6%	43%	52,813,716	62,332,369	2.3%	899,527,000	9.16%	82,396,673	3.9%	197,542,758	3.3%	57%	298,276,498	1.0%
1999	85,548,421	32,589,300	9,172,275	108,965,446	7.9%	44%	56,338,252	64,613,305	3.6%	924,688,000	9.16%	84,701,421	2.8%	205,652,978	4.0%	56%	314,618,424	5.3%
2000	79,148,841	43,502,164	(5,662,827)	128,313,832	16.3%	47%	59,608,189	67,641,053	4.6%	941,817,000	9.16%	86,270,437	1.8%	213,519,680	3.8%	53%	341,833,511	8.3%
2001	76,577,962	39,031,223	(7,752,346)	123,361,531	-3.9%	45%	60,799,285	68,502,294	1.3%	965,566,000	9.16%	88,445,846	2.5%	217,747,425	2.0%	55%	341,108,956	-0.2%
2002	78,962,037	41,149,116	(2,628,214)	122,739,368	-0.5%	44%	63,613,127	69,699,634	1.7%	993,499,000	9.16%	91,004,508	2.9%	224,317,269	3.0%	56%	347,056,637	1.7%
2003	97,795,315	38,255,213	15,855,710	120,194,818	-2.1%	43%	67,081,506	69,807,293	0.2%	1,011,420,000	9.16%	92,646,072	1.8%	229,534,871	2.3%	57%	349,729,689	0.8%
2004	103,150,677	47,839,131	10,430,743	140,559,065	15.7%	46%	69,427,254	74,874,195	7.0%	1,058,206,000	9.16%	96,931,670	4.5%	241,233,118	5.0%	54%	381,792,183	8.8%
2005	114,134,301	52,542,439	17,303,717	149,373,023	6.1%	46%	70,634,350	80,726,030	7.5%	1,121,604,000	9.04%	101,336,921	4.4%	252,697,301	4.6%	54%	402,070,324	5.2%
2006	125,593,992	56,725,590	27,497,697	154,821,885	3.6%	47%	74,797,964	84,952,047	5.1%	1,144,768,000	8.66%	99,136,909	-2.2%	258,886,920	2.4%	53%	413,708,805	2.9%
2007	147,147,190	62,199,891	34,835,459	174,511,622	12.0%	49%	78,971,519	88,795,537	4.4%	1,162,237,000	8.65%	100,572,242	1.4%	268,339,297	3.6%	51%	442,850,919	6.8%
Averages																		
1996-2007	99,202,673	41,909,692		127,827,902	$\boxed{4.5\%}$	45%	62,593,121	70,939,954	3.8%	992,198,250		89,800,817	2.7%	223,333,892	3.7%	55%	351,161,794	$\boxed{4.0\%}$

[1] Taxes here are estimated by PEG based on the costs that would be subject to the revenue adjustment mechanism. They include income and operating taxes other than income but do not include the portion of revenue tax that is paid for retirement, purchase power, DSM, IRP, or fuel. They are displayed here for reference only; taxes are generated by each escalation mechanism throughout these simulations to reflect the impact of the mechanism on income and revenue taxes.

* All growth rates are calculated logarithmically. The growth rate of any variable X between years t-1 and t is calculated as $\ln(X_t/X_{t-1})$.
Arithmetic growth rates are an alternative methodology that merits consideration.

Source: Taxes calculated by PEG. Other cost data provided by HECO staff.

Comments

Costs used in simulations exclude all retirement, fuel, purchased power, DSM, and IRP costs.
Taxes exclude the portion of revenue taxes that is attributable to fuel, purchased power, retirement, DSM, and IRP costs.
Capital accounts for a sizable share of total cost.
HECO's comparatively slow cost growth reflects in part its slower output growth.

Table 5b

COST OF SERVICE CALCULATIONS

	Net O&M Expenses						*Capital Costs*										*Total COS*	
	Non-Energy, Non-Capacity																	
Year	Operation [A]	Maintenance [B]	Retirement Expense, DSM & IRP [C]	Subtotal [D]=[A]+[B]-[C]	GR*	% of Total Cost [D]/[K]	Net Depreciation + Amortization [E]	Taxes[1] [F]	GR*	Rate Base [G]	HPUC Target ROR [H]	Required Return on Rate Base [I]=[G]x[H]	GR*	Total Capital Cost [J]=[E]+[F]+[I]	GR*	% of Total [J]/[K]	Cost [K]=[D]+[J]	GR*
HELCO																		
1996	22,913,130	10,132,109	5,347,490	27,697,749		44%	14,652,439	16,187,329		226,319,000	9.34%	21,138,195		51,977,963		56%	79,675,712	
1997	25,881,193	8,972,749	5,611,494	29,242,448	5.4%	43%	15,865,770	16,995,364	4.9%	240,321,000	9.34%	22,445,981	6.0%	55,307,116	6.2%	57%	84,549,563	5.9%
1998	24,471,933	8,229,608	3,829,520	28,872,022	-1.3%	42%	16,903,437	17,491,908	2.9%	249,447,000	9.34%	23,298,350	3.7%	57,693,694	4.2%	58%	86,565,716	2.4%
1999	23,854,328	9,639,205	2,589,078	30,904,455	6.8%	42%	17,905,674	18,450,180	5.3%	263,198,000	9.34%	24,582,693	5.4%	60,938,547	5.5%	58%	91,843,003	5.9%
2000	19,591,319	9,328,348	(207,308)	29,126,974	-5.9%	40%	19,341,331	19,027,025	3.1%	270,798,000	9.30%	25,175,187	2.4%	63,543,543	4.2%	60%	92,670,518	0.9%
2001	18,680,020	9,444,128	(454,036)	28,578,183	-1.9%	41%	18,521,920	17,874,597	-6.2%	256,241,000	9.15%	23,435,375	-7.2%	59,831,892	-6.0%	59%	88,410,075	-4.7%
2002	21,269,982	13,437,227	(19,858)	34,727,068	19.5%	45%	19,547,853	17,978,264	0.6%	241,576,000	9.14%	22,080,046	-6.0%	59,606,163	-0.4%	55%	94,333,231	6.5%
2003	25,151,744	13,737,078	3,043,807	35,845,015	3.2%	46%	20,292,930	18,101,232	0.7%	240,281,000	9.14%	21,961,683	-0.5%	60,355,845	1.2%	54%	96,200,860	2.0%
2004	24,201,192	15,144,948	1,837,236	37,508,904	4.5%	44%	21,163,467	20,936,950	14.6%	294,091,000	9.14%	26,879,917	20.2%	68,980,334	13.4%	56%	106,489,238	10.2%
2005	26,056,508	16,503,630	2,538,870	40,021,268	6.5%	40%	27,176,911	24,856,323	17.2%	358,815,000	9.14%	32,795,691	19.9%	84,828,925	20.7%	60%	124,850,192	15.9%
2006	29,755,125	19,668,695	4,049,650	45,374,171	12.6%	41%	29,722,210	26,880,410	7.8%	378,695,000	9.14%	34,612,723	5.4%	91,215,343	7.3%	59%	136,589,513	9.0%
2007	32,622,128	20,700,180	4,787,303	48,535,004	6.7%	44%	30,093,978	25,940,242	-3.6%	377,547,000	8.53%	32,214,198	-7.2%	88,248,418	-3.3%	56%	136,783,422	0.1%
Averages 1996-2007	24,537,384	12,911,492		34,702,772	$\boxed{5.1\%}$	43%	20,932,327	20,059,985	4.3%	283,110,750		25,885,003	3.8%	66,877,315	4.8%	57%	101,580,087	$\boxed{4.9\%}$

[1] Taxes here are estimated by PEG based on the costs that would be subject to the revenue adjustment mechanism. They include income and operating taxes other than income but do not include the portion of revenue tax that is paid for retirement, purchase power, DSM, IRP, or fuel. They are displayed here for reference only; taxes are generated by each escalation mechanism throughout these simulations to reflect the impact of the mechanism on income and revenue taxes.

* All growth rates are calculated logarithmically. The growth rate of any variable X between years t-1 and t is calculated as $\ln(X_t/X_{t-1})$. Arithmetic growth rates are an alternative methodology that merits consideration.

Source: Taxes calculated by PEG. Other cost data provided by HECO staff.

Comments

Costs used in simulations exclude all retirement, fuel, purchased power, DSM, and IRP costs.
Taxes exclude the portion of revenue taxes that is attributable to fuel, purchased power, retirement, DSM, and IRP costs.
Capital accounts for a sizable share of total cost.
HELCO's comparatively rapid cost growth reflects in part its rapid output growth.

Table 5c

COST OF SERVICE CALCULATIONS

Year	Net O&M Expenses: Non-Energy, Non-Capacity: *Operation* [A]	*Maintenance* [B]	Retirement Expense, *DSM & IRP* [C]	*Subtotal* [D]=[A]+[B]-[C]	*GR**	% of Total *Cost* [D]/[K]	Capital Costs: Net Depreciation + *Amortization* [E]	*Taxes*[1] [F]	*GR**	*Rate Base* [G]	HPUC Target *ROR* [H]	Required Return *on Rate Base* [I]=[G]x[H]	*GR**	Total Capital *Cost* [J]=[E]+[F]+[I]	*GR**	% of *Total* [J]/[K]	Total COS: *Cost* [K]=[D]+[J]	*GR**
MECO																		
1996	22,911,685	10,416,521	3,046,440	30,281,766		47%	12,700,935	16,818,672		237,585,000	9.27%	22,024,130		51,543,736		53%	81,825,502	
1997	26,153,258	9,867,828	4,049,513	31,971,573	5.4%	46%	15,218,507	17,169,612	2.1%	238,237,000	9.27%	22,084,570	0.3%	54,472,689	5.5%	54%	86,444,261	5.5%
1998	24,908,574	8,645,461	4,051,547	29,502,489	-8.0%	41%	15,937,832	19,061,186	10.5%	294,705,000	9.13%	26,906,567	19.7%	61,905,585	12.8%	59%	91,408,073	5.6%
1999	20,509,945	15,196,156	3,063,799	32,642,302	10.1%	41%	19,057,370	20,332,831	6.5%	311,664,000	8.85%	27,590,056	2.5%	66,980,257	7.9%	59%	99,622,558	8.6%
2000	19,927,007	13,236,247	3,029,747	30,133,507	-8.0%	39%	19,567,378	20,548,081	1.1%	319,511,000	8.83%	28,212,821	2.2%	68,328,281	2.0%	61%	98,461,788	-1.2%
2001	24,849,647	13,098,891	2,899,141	35,049,397	15.1%	41%	21,392,538	21,439,917	4.2%	328,549,000	8.83%	29,010,877	2.8%	71,843,332	5.0%	59%	106,892,729	8.2%
2002	26,712,239	11,692,550	2,990,026	35,414,763	1.0%	41%	22,263,203	21,612,807	0.8%	327,503,000	8.83%	28,918,515	-0.3%	72,794,525	1.3%	59%	108,209,288	1.2%
2003	26,742,251	12,379,110	3,845,192	35,276,169	-0.4%	40%	23,145,650	21,916,137	1.4%	331,290,000	8.83%	29,252,907	1.1%	74,314,694	2.1%	60%	109,590,863	1.3%
2004	26,136,822	14,320,973	3,405,719	37,052,076	4.9%	41%	24,289,974	22,144,769	1.0%	334,190,000	8.83%	29,508,977	0.9%	75,943,720	2.2%	59%	112,995,796	3.1%
2005	28,230,613	13,190,885	4,211,108	37,210,391	0.4%	41%	25,006,454	22,102,810	-0.2%	328,901,000	8.83%	29,041,958	-1.6%	76,151,222	0.3%	59%	113,361,613	0.3%
2006	29,818,963	13,816,285	3,850,114	39,785,135	6.7%	41%	25,644,288	23,431,066	5.8%	350,245,000	8.83%	30,926,634	6.3%	80,001,988	4.9%	59%	119,787,122	5.5%
2007	31,916,646	22,835,609	4,151,019	50,601,237	24.0%	45%	28,015,427	26,190,545	11.1%	382,449,000	8.83%	33,770,247	8.8%	87,976,218	9.5%	55%	138,577,455	14.6%
Averages 1996-2007	25,734,804	13,224,710		35,410,067	4.7%	42%	21,019,963	21,064,036	4.0%	315,402,417		28,104,021	3.9%	70,188,021	4.9%	58%	105,598,087	4.8%

[1] Taxes here are estimated by PEG based on the costs that would be subject to the revenue adjustment mechanism. They include income and operating taxes other than income but do not include the portion of revenue tax that is paid for retirement, purchase power, DSM, IRP, or fuel. They are displayed here for reference only; taxes are generated by each escalation mechanism throughout these simulations to reflect the impact of the mechanism on income and revenue taxes.

* All growth rates are calculated logarithmically. The growth rate of any variable X between years t-1 and t is calculated as $\ln(X_t/X_{t-1})$. Arithmetic growth rates are an alternative methodology that merits consideration.

Source: Taxes calculated by PEG. Other cost data provided by HECO staff.

Comments

Costs used in simulations exclude all retirement, fuel, purchased power, DSM, and IRP costs.

Taxes exclude the portion of revenue taxes that is attributable to fuel, purchased power, retirement, DSM, and IRP costs.

Capital accounts for a sizable share of total cost.

- Utility Service Workers

Price indexes are also computed for other categories of electric utility O&M expenses. Indexes are available at the most detailed level at which O&M expense data are reported on the FERC Form 1. Global Insight also calculates indexes that summarize the trends in these most detailed indexes for each major FERC Form 1 operating category. These categories comprise

- Steam production plant
- Nuclear production plant
- Hydro production plant
- Other production plant
- Transmission plant
- Distribution plant
- Customer accounts
- Customer service and information
- Administrative and general

Global Insight maintains, additionally, a summary input price index for all "other" electric utility O&M expenses (called JETOTALMS) and for all O&M expenses (called JETOTAL).

Table 6a reports the Global Insight salary and wage price indexes for the 1990-2007 period. Inspecting the results, it can be seen that the growth trend for salary and wage prices of electric power generation, transmission, and distribution workers was modestly higher than that for all utility service workers. Table 6b reports a summary wage and salary price index, prepared by PEG, that is constructed from the three Global Insight salary and wage price indexes that SCE has used in its RAM. The growth rate of the index is a cost weighted average of the growth rates of the three subindexes. The cost shares used in index calculations are those from recent testimony for SCE because they are unavailable from HECO.

Table 6a

ALTERNATIVE SALARY AND WAGE PRICE INDEXES

	Electric Power Generation, Transmission & Distr. Workers		Managers and Administrators		Professional and Technical Workers		Utility Service Workers: CEU4422000008	
Year	Index	Growth Rate*	Index	Growth Rate*	Index	Growth Rate*	Index	Growth Rate*
1990	16.232		1.053		1.057		16.139	
1991	16.823	3.58%	1.099	4.28%	1.103	4.26%	16.703	3.43%
1992	17.213	2.29%	1.123	2.16%	1.146	3.82%	17.166	2.73%
1993	17.948	4.18%	1.158	3.07%	1.184	3.26%	17.955	4.49%
1994	18.700	4.10%	1.193	2.98%	1.217	2.75%	18.666	3.88%
1995	19.230	2.79%	1.231	3.14%	1.249	2.60%	19.193	2.78%
1996	19.908	3.47%	1.277	3.67%	1.290	3.23%	19.782	3.02%
1997	20.829	4.52%	1.331	4.14%	1.330	3.05%	20.595	4.03%
1998	21.804	4.57%	1.395	4.70%	1.379	3.62%	21.480	4.21%
1999	22.438	2.87%	1.451	3.94%	1.423	3.14%	22.028	2.52%
2000	23.123	3.01%	1.513	4.18%	1.478	3.79%	22.753	3.24%
2001	23.922	3.40%	1.568	3.57%	1.540	4.11%	23.582	3.58%
2002	24.579	2.71%	1.634	4.12%	1.577	2.37%	23.959	1.59%
2003	25.653	4.28%	1.709	4.49%	1.613	2.26%	24.768	3.32%
2004	26.487	3.20%	1.743	1.97%	1.665	3.17%	25.611	3.35%
2005	27.623	4.20%	1.777	1.93%	1.714	2.90%	26.676	4.07%
2006	28.353	2.61%	1.826	2.72%	1.771	3.27%	27.402	2.69%
2007	29.243	3.09%	1.887	3.29%	1.839	3.77%	27.867	1.68%
Period Averages:								
1996-2007	**3.50%**		**3.55%**		**3.22%**		**3.12%**	
Standard Deviations:								
1996-2007		**0.75%**		**0.96%**		**0.58%**		**0.91%**

Source: Global Insight Power Planner Table A30, Utility Price and Wage Indicators, Quarter 3, 2008.

Table 6b

PEG SALARY AND WAGE PRICE INDEX CONSTRUCTION, 1990-2007

	Cost Shares[1]			Global Insight Salary & Wage Price Indexes[2]						Salaries & Wages Index[3]	
	Clerical	Executive / Management	Professional	Electric Power Generation, Transmission & Distr. Workers		Managers and Administrators		Professional and Technical Workers			
				Level	GR*	Level	GR*	Level	GR*	Index	GR*
	[A]	[B]	[C]		[D]		[E]		[F]		[G]
1990	46%	20%	34%	16.232		1.053		1.057		1.000	
1991	46%	20%	34%	16.823	3.58%	1.099	4.28%	1.103	4.26%	1.040	3.95%
1992	46%	20%	34%	17.213	2.29%	1.123	2.16%	1.146	3.82%	1.070	2.79%
1993	46%	20%	34%	17.948	4.18%	1.158	3.07%	1.184	3.26%	1.109	3.65%
1994	46%	20%	34%	18.700	4.10%	1.193	2.98%	1.217	2.75%	1.148	3 42%
1995	46%	20%	34%	19.230	2.79%	1.231	3.14%	1.249	2.60%	1 181	2.80%
1996	46%	20%	34%	19.908	3.47%	1.277	3.67%	1.290	3.23%	1.222	3.43%
1997	46%	20%	34%	20.829	4.52%	1.331	4 14%	1.330	3.05%	1.271	3.95%
1998	46%	20%	34%	21.804	4.57%	1.395	4 70%	1.379	3.62%	1.326	4.27%
1999	46%	20%	34%	22.438	2.87%	1.451	3.94%	1.423	3.14%	1 369	3.17%
2000	46%	20%	34%	23.123	3.01%	1.513	4.18%	1.478	3.79%	1.418	3.51%
2001	46%	20%	34%	23.922	3.40%	1.568	3.57%	1 540	4.11%	1 471	3.67%
2002	46%	20%	34%	24 579	2.71%	1.634	4.12%	1.577	2.37%	1.514	2.88%
2003	46%	20%	34%	25.653	4.28%	1.709	4 49%	1.613	2.26%	1.570	3.63%
2004	46%	20%	34%	26.487	3.20%	1.743	1.97%	1 665	3.17%	1.617	2.94%
2005	46%	20%	34%	27 623	4.20%	1.777	1.93%	1.714	2 90%	1.671	3.30%
2006	46%	20%	34%	28.353	2.61%	1.826	2.72%	1.771	3.27%	1.720	2.86%
2007	46%	20%	34%	29.243	3.09%	1 887	3.29%	1 839	3.77%	1.778	3.36%
Average Annual Growth Rate 1996-2007					**3.50%**		**3.55%**		**3.22%**		**3.41%**

[1] Cost shares are those reported by SCE in a 2004 rate filing.

[2] Historic salary and wage price index values reported by Global Insight and represent Electric Power Generation, Transmission, and Distribution Workers: CEU4422110008; Managers and Administrators: ECIPWMBFNS; and Professional and Technical Workers: ECIPWPARNS; detailed on Table 5a.

[3] Growth of the salary and wage index is the cost share weighted average of the growth of these three Global Insight price indexes and is calculated as
[G] = [A]X[D] + [B]X[E] + [C]X[F].

* *All growth rates are calculated logarithmically. The growth rate of any variable X between years t-1 and t is calculated as* $ln(X_t/X_{t-1})$. *Arithmetic growth rates are an alternative* methodology that merits consideration.

Table 7 reports results of Global Insight summary indexes of the prices of other O&M expenses for 7 FERC broad categories of operations. The table also reports two kinds of indexes that summarize the inflation in such indexes. The first is the JETOTALMS index prepared by Global Insight. It appears to be calculated using typical industry cost share weights. We also present the results of more customized summary indexes prepared by PEG for HECO, HELCO, and MECO. These indexes use the O&M expenses of each company to calculate cost share weights. It can be seen that the summary Global Insight index grew a little faster than the custom PEG indexes.

Table 8 presents results for the 1982-1997 period for some alternative macroeconomic price indexes.

- The gross domestic product price index ("GDPPI")
- The CPI - all items (CPI-U) for Honolulu and the nation
- The core CPI for Honolulu and the nation.

The table reports the standard deviations of the growth rates of the indexes as well as their average annual growth rates for selected intervals.

Inspecting the results, it is noteworthy first of all that the growth trends of the GDPPI and the CPIs are well below those of the Global Insight indexes. During the simulation years, for instance, the CPI-U for Honolulu averaged 2.29% annual growth whereas JETOTALMS averaged 3.14% growth. This result isn't surprising inasmuch as the macroeconomic measures of output price inflation reflect the substantial multifactor productivity trend of the economy.

It is also noteworthy that the CPI-U for Honolulu is much less stable than its national counterpart. Its annual inflation ranged from -0.2% in 1998 to 5.70% in 2006. During the same years, the inflation of the national CPI-U was 1.55% and 3.17% respectively.

5.3 RAMs Considered

The hybrid approach to RAM design is discussed in Sections 2 and 3 above. We reported that indexation is commonly used to escalate O&M expenses. Minor plant additions are

Table 7

INPUT PRICE INDEXES FOR OTHER O&M EXPENSES, 1990-2007

	Global Insight Indexes for Specific Cost Categories																PEG Summary Input Price Indexes[1]					
	Production Steam Generation (JEFOMMS)		Production Other Power Generation (JEOOMMS)		Transmission (JETOMMS)		Distribution (JEDOMMS)		Customer Accounts (JECAOMMS)		Customer Service and Information (JECSIOMS)		A&G (JEADGOMMS)		Total O&M (JETOTALMS)		HECO		HELCO		MECO	
	Index	GR*	Index	GR*	Index	GR*	Index	GR*	Index	GR*	Index	GR*	Index	GR*	Index	GR*	Index	GR*	Index	GR*	Index	GR*
1990	0.961		0.973		0.970		0.960		0.952		0.963		0.907		0.942		NA		NA		NA	
1991	0.986	2.57%	0.986	1.33%	0.985	1.53%	0.984	2.47%	0.986	3.51%	0.989	2.66%	0.957	5.37%	0.975	3.44%	NA		NA		NA	
1992	1.000	1.41%	1.000	1.41%	1.000	1.51%	1.000	1.61%	1.000	1.41%	1.000	1.11%	1.000	4.40%	1.000	2.53%	NA		NA		NA	
1993	1.017	1.69%	1.010	1.00%	1.015	1.49%	1.022	2.18%	1.012	1.19%	1.017	1.69%	1.039	3.83%	1.025	2.47%	NA		NA		NA	
1994	1.046	2.81%	1.047	3.60%	1.048	3.20%	1.046	2.32%	1.034	2.15%	1.043	2.52%	1.077	3.59%	1.056	2.98%	NA		NA		NA	
1995	1.085	3.66%	1.066	1.80%	1.078	2.82%	1.085	3.66%	1.090	5.27%	1.101	5.41%	1.117	3.65%	1.096	3.72%	NA		NA		NA	
1996	1.100	1.37%	1.070	0.37%	1.086	0.74%	1.103	1.65%	1.107	1.55%	1.124	2.07%	1.149	2.82%	1.118	1.99%	1.000		1.000		1.000	
1997	1.122	1.98%	1.098	2.58%	1.108	2.01%	1.124	1.89%	1.121	1.26%	1.140	1.41%	1.182	2.83%	1.142	2.12%	1.022	2.22%	1.023	2.27%	1.024	2.38%
1998	1.132	0.89%	1.100	0.18%	1.111	0.27%	1.124	0.00%	1.132	0.98%	1.152	1.05%	1.216	2.84%	1.160	1.56%	1.038	1.47%	1.034	1.11%	1.035	1.03%
1999	1.141	0.79%	1.107	0.63%	1.118	0.63%	1.133	0.80%	1.152	1.75%	1.166	1.21%	1.252	2.92%	1.179	1.62%	1.055	1.70%	1.049	1.41%	1.047	1.22%
2000	1.164	2.00%	1.130	2.06%	1.144	2.30%	1.165	2.79%	1.183	2.66%	1.198	2.71%	1.300	3.76%	1.215	3.01%	1.086	2.85%	1.077	2.66%	1.073	2.43%
2001	1.186	1.87%	1.144	1.23%	1.159	1.30%	1.181	1.36%	1.213	2.50%	1.224	2.15%	1.347	3.55%	1.244	2.36%	1.113	2.43%	1.100	2.06%	1.091	1.79%
2002	1.200	1.17%	1.155	0.96%	1.168	0.77%	1.190	0.76%	1.230	1.39%	1.236	0.98%	1.393	3.36%	1.268	1.91%	1.134	1.92%	1.116	1.49%	1.108	1.38%
2003	1.227	2.23%	1.170	1.29%	1.183	1.28%	1.217	2.24%	1.257	2.17%	1.265	2.32%	1.447	3.80%	1.303	2.72%	1.166	2.73%	1.142	2.28%	1.132	2.17%
2004	1.296	5.47%	1.210	3.36%	1.229	3.81%	1.278	4.89%	1.278	1.66%	1.296	2.42%	1.508	4.13%	1.360	4.28%	1.219	4.47%	1.192	4.26%	1.176	3.84%
2005	1.380	6.28%	1.287	6.17%	1.298	5.46%	1.354	5.78%	1.317	3.01%	1.351	4.16%	1.572	4.16%	1.428	4.88%	1.284	5.17%	1.257	5.34%	1.241	5.35%
2006	1.459	5.57%	1.342	4.18%	1.355	4.30%	1.442	6.30%	1.355	2.84%	1.391	2.92%	1.634	3.87%	1.495	4.59%	1.346	4.75%	1.317	4.67%	1.296	4.37%
2007	1.516	3.83%	1.389	3.44%	1.403	3.48%	1.504	4.21%	1.395	2.91%	1.435	3.11%	1.699	3.90%	1.557	4.06%	1.398	3.79%	1.368	3.74%	1.344	3.64%
Average Annual Growth Rate																						
1990-2007		2.68%		2.09%		2.17%		2.64%		2.25%		2.35%		3.69%		2.96%		NA		NA		NA
1996-2007		2.92%		2.37%		2.33%		2.82%		2.10%		2.32%		3.56%		3.01%		3.05%		2.85%		2.69%
Standard Deviation of Annual Growth Rates																						
1990-2007		1.71%		1.59%		1.46%		1.78%		1.08%		1.16%		0.65%		1.04%		NA		NA		NA
1996-2007		2.02%		1.80%		1.70%		2.16%		0.73%		1.00%		0.50%		1.23%		1.29%		1.49%		1.42%

Source: Global Insight Power Planner, Total Operations & Maintenance, Tables A22-25, Quarter 3, 2008.

[1] Growth of PEG's summary M&S input price indexes are cost share weighted averages of the growth of seven Global Insight electric utility M&S input price subindexes. The cost shares are supplied by HECO staff, and historical index values are as reported by Global Insight.

* All growth rates are calculated logarithmically. The growth rate of any variable X between years t-1 and t is calculated as $\ln(X_t/X_{t-1})$. Arithmetic growth rates are an alternative methodology that merits consideration.

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Table 8

MACROECONOMIC PRICE INDEX COMPARISONS FOR HAWAII, 1990-2007

	GDPPI^{USA}		Implicit Price Index, Hawaii GDP[2] Nominal		Implicit Price Index, Hawaii GDP[2] Real		Implicit Price Index, Hawaii GDP[2] GDPIPI^{Hawaii}		Core CPI All Cities[3]		Core CPI Honolulu[4]		CPI-U All Cities[5]		CPI-U Honolulu[6]	
	Index[1]	GR*	Index	GR*	Index	GR*	Index	GR*	Index	GR*	Index	GR*	Index	GR*	Index	GR*
		[A]	[n]		[r]		[b] = [n] / [r]	[B]		[R]		[S]		[T]		[U]
1982	62.74		NA		NA		NA		95 8		96 6		96.5			
1983	65 71	3 87%	NA		NA		NA		99 6	3 89%	99.5	2 96%	99 8	3 16%		
1984	67 66	3 69%	NA		NA		NA		104 6	4 90%	104 0	4 42%	103.9	4 23%	103 5	
1985	69 72	3 00%	NA		NA		NA		109 1	4 21%	107 8	3.59%	107 6	3.50%	106 8	3 14%
1986	71 27	2.19%	NA		NA		NA		113 5	3 95%	112 7	4 45%	109 6	1 84%	109 4	2 41%
1987	73 20	2 68%	NA		NA		NA		118 2	4 06%	119 1	5 52%	113 6	3 58%	114 9	4 91%
1988	75.71	3.36%	NA		NA		NA		123 4	4 31%	127 0	6 42%	118 3	4 05%	121 7	5 75%
1989	78 57	3 71%	NA		NA		NA		129 0	4 44%	134 0	5 37%	124 0	4 71%	128.7	5.59%
1990	81 61	3 80%	31581		40962		0 77		135 5	4 92%	143 4	6 78%	130.7	5 26%	138.1	7 05%
1991	84 46	3 42%	33245	5 14%	41339	0 91%	0 80	4 22%	142 1	4 76%	154 6	7 52%	136 2	4 12%	148 0	6 92%
1992	86 40	2 28%	34854	4 73%	42215	2 10%	0 83	2 63%	147 3	3 59%	163 4	5 54%	140 3	2 97%	155.1	4 69%
1993	88.39	2 27%	35572	2 04%	41877	-0 81%	0 85	2 84%	152 2	3 27%	168 2	2 90%	144 5	2 95%	160 1	3 17%
1994	90 27	2.10%	35896	0 91%	41253	-1.50%	0 87	2.41%	156 5	2.79%	174 1	3 45%	148 2	2.53%	164 5	2 71%
1995	92 12	2 03%	36208	0 87%	40711	-1.32%	0 89	2 19%	161 2	2 96%	177 5	1 93%	152 4	2 79%	168 1	2 16%
1996	93 86	1 88%	36592	1 05%	40330	0.94%	0 91	1 99%	165 6	2 69%	180.5	1 68%	156.9	2 91%	170 7	1 53%
1997	95 42	1 64%	37546	2 57%	40412	0 20%	0 93	2.37%	169 5	2 33%	181 4	0 50%	160 5	2 27%	171 9	0 70%
1998	96 48	1 10%	37549	0 01%	39568	2.11%	0 95	2 12%	173 4	2 27%	181.3	-0.06%	163 0	1.55%	171.5	-0 23%
1999	97 87	1 43%	38675	2 83%	39747	0 45%	0 97	2 37%	177.0	2 05%	183 0	0 93%	166 6	2 18%	173 3	1 04%
2000	100 00	2 16%	40202	4 00%	40202	1 14%	1 00	2 86%	181.3	2 40%	185 1	1 14%	172 2	3 31%	176.3	1 77%
2001	102 40	2 37%	41822	3 95%	40626	1 05%	1 03	2 90%	186 1	2.61%	186 5	0 75%	177 1	2 81%	178.4	1.18%
2002	104.19	1.73%	43476	3 88%	41093	1 14%	1 06	2 74%	190 5	2.34%	189 5	1 60%	179 9	1.57%	180 3	1 06%
2003	106 41	2.10%	46441	6 60%	42580	3 55%	1 09	3 04%	193 2	1.41%	192 6	1 62%	184 0	2 25%	184 5	2.30%
2004	109 46	2.83%	50414	8 21%	44636	4 72%	1 13	3 49%	196 6	1.74%	198 4	2 97%	188 9	2 63%	190 6	3 25%
2005	113 01	3 19%	54863	8 46%	46939	5 03%	1 17	3 43%	200 9	2.16%	204 4	2 98%	195 3	3 33%	197 8	3.71%
2006	116.57	3.10%	58676	6 72%	48428	3 12%	1 21	3 60%	205 9	2 46%	215 6	5 33%	201 6	3 17%	209 4	5 70%
2007	119 67	2 62%	61532	4 75%	49860	2 91%	1 23	1 84%	210 7	2 32%	225.9	4 68%	207.3	2.81%	219 5	4 71%
Average Annual Growth Rate																
1990-2007		2.25%		3.92%		1.16%		2.77%		2.60%		2.67%		2.71%		2.78%
1996-2007		2.21%		4 72%		1 93%		2.80%		2.19%		2.04%		2.58%		2 29%
Standard Deviation of Annual Growth Rates																
1990-2007		0.63%		2 57%		2.16%		0 64%		0 76%		2.07%		0.64%		1.93%
1996-2007		0 69%		2 57%		2.14%		0 58%		0 94%		1.74%		0.63%		1.84%

Comments

GDPPI is much more stable than the core CPI and CPI-U for Hawaii. Hawaii's CPI inflation has been more rapid than the nation's in recent years but is similar in the longer term.

[1] Price Index represents Gross Domestic Product, NIPA Table 1 1 4 - Bureau of Economic Analysis (Data updated monthly, data for 2007 finalized and released on March 27, 2008; updated October 30, 2008)

[2] Source. Bureau of Economic Analysis, U.S Department of Commerce: Regional Economic Accounts, GDP by State (Data available annually, "advance" data for 2007 released June 5, 2008; revisions possible in subsequent years)

[3] US (Core) CPI Index - All Cities, All Items Less Food and Energy (Not Seasonally Adjusted) - Bureau of Labor Statistics (Data available monthly, final data for 2007 released January 16, 2008)

[4] (Core) CPI Index - Honolulu, HI, All Items Less Food and Energy (Not Seasonally Adjusted) - Bureau of Labor Statistics (Data available semi-annually, final data for 2007 released February 20, 2008)

[5] CPI Index - All Cities, USA, All Items (Not Seasonally Adjusted) - Bureau of Labor Statistics (Data available semi-annually, final data for 2007 released February 20, 2008)

[6] CPI Index - Honolulu, HI, All Items (Not Seasonally Adjusted) - Bureau of Labor Statistics (Data available semi-annually, final data for 2007 released February 20, 2008).

* All growth rates are calculated logarithmically. The growth rate of any variable X between years t-1 and t is calculated as $\ln(X_t/X_{t-1})$

Arithmetic growth rates are an alternative methodology that merits consideration.

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sometimes forecasts and sometimes fixed in real terms and then subject to adjustment for construction cost inflation.

HECO is proposing to forecast its plant additions during the decoupling plans. We accordingly assume for purposes of our calculations a perfect foresight treatment of depreciation and the rate base. The tax component of the revenue requirement is forecasted to reflect these costs and the O&M expenses that are generated by a formulaic escalator.

With this specification, results for hybrid RAMs vary only due to differences in the escalators for O&M expenses. Six kinds of O&M escalators are considered, all of which are formulaic.

Hybrid 1 (PEG Custom Input Price Index)

Cost is escalated only for the growth in a custom O&M input price index. This index was developed by PEG using Global Insight indexes. The indexes employed are substantially the same as those used in the RAM of SCE. This includes the summary salary and wage price index that is detailed in Table 6b.

Hybrid 2 (PEG 3-Category Decomposition)

Cost is decomposed into three categories:

- Salaries and wages
- A&G expenses
- Other O&M expenses

The A&G category is escalated by the summary Global Insight index for other A&G expenses. The salary and wage category is escalated by the summary salary and wage price index detailed in Table 6b. The other O&M expenses are escalated by custom input price indexes developed by PEG from Global Insight indexes.

These three indexes are expressly designed to be consistent with the PEG custom summary index used in Hybrid 1. We would accordingly expect virtually identical results.

Hybrid 3 (Full Indexation)

Cost is escalated by a formula that takes account of each company's customer growth and a common 1.26% productivity factor. This factor was calculated by PEG and is the average annual growth in the O&M productivity of a sample of forty three vertically integrated electric utilities. The sample period was 1996-2006. The year 2006 was the latest for which the necessary data have been gathered. The same custom inflation measure is used as in Hybrid 1.

Hybrid 4 (GDPPI)

Cost is escalated by the gross domestic product price index for the United States.

Hybrid 5 (GDPPI)

Cost is escalated by the CPI-U for Honolulu.

Hybrid 6 (Global Insight Summary Inflation Index)

Cost is escalated by Global Insight's summary salary and wage price index for the other O&M expenses of electric utilities (JETOTALMS).

Hybrid 7 (HECO 12 category disaggregated)

Cost is decomposed into 12 cost categories.

- Production Salaries and Wages
- Production Other O&M
- Transmission Salaries and Wages
- Transmission Other O&M
- Distribution Salaries and Wages
- Distribution Other O&M
- Customer Accounts Salaries and Wages
- Customer Accounts Other O&M
- Customer Service & Information Salaries and Wages
- Customer Service & Information Other O&M

- A&G Salaries and Wages
- A&G Other O&M

Each category is escalated by a single Global Insight inflation index. No summary salary and wage price index is used, as in the RAM of SCE. The mix of labor subindexes differs from Edison's. In particular, the index for professional and technical workers is not used and the index for utility service workers is used. This proposed treatment sidesteps the problem of estimating the breakdown of salaries and wages with regard to managers & administrators, professional and technical workers, and workers in line functions.

Revenue Per Customer Freeze

This is a simple RPC freeze rather than an RPC freeze by service class. The total applicable revenue requirement should grow at the pace of total customer growth.

Inflation Only

In this RAM, the total applicable revenue requirement grows at the pace of the U.S. economy's GDPPI inflation.

5.4 Simulation Results

5.4.1 Hybrid RAMs

Results of the simulations for O&M expenses of hybrid RAMs appear in Table 9. Here is a summary of highlights.

Hybrid 1 (PEG Custom Input Price Index)

This escalator is overcompensatory for HECO. The O&M budget was 1.9% above the actuals on average during attrition years. This result reflects in part the fact that the escalator isn't designed to capture the cost impact of HECO's slow output growth. The escalator is uncompensatory for HELCO and MECO. This result reflects in part the fact that it isn't designed to capture the cost impact of HELCO's and MECO's brisk output growth. The escalator is a little uncompensatory on balance for the three companies.

Table 9

FINANCIAL SUFFICIENCY SIMULATION: SUMMARY OF HYBRID O&M SUFFICIENCY

	HECO		HELCO		MECO		All Company Total	
	Average Revenue Surplus (Shortfall) [1] [A]	Average Revenue / Cost [1]	Average Revenue Surplus (Shortfall) [1] [B]	Average Revenue / Cost [1]	Average Revenue Surplus (Shortfall) [1] [C]	Average Revenue / Cost [1]	Average Revenue Surplus (Shortfall) [A]+[B]+[C]	Average Revenue / Cost [1]
Hybrid I (PEG Custom Input Price Index)								
3 yr	(2,776,165)	0.987	(392,540)	1.002	(673,064)	0.996	(3,841,769)	0.995
4 yr	4,741,287	1.048	(2,226,910)	0.946	(1,757,333)	0.960	757,044	0.984
Average	**1,203,662**	**1.019**	**(1,363,677)**	**0.972**	**(1,247,089)**	**0.977**	**(1,407,103)**	**0.989**
Hybrid II (PEG 3 Category Decomposition)								
3 yr	(2,754,553)	0.987	(383,378)	1.003	(669,153)	0.996	(3,807,084)	0.995
4 yr	4,735,816	1.048	(2,210,164)	0.946	(1,753,940)	0.960	771,712	0.985
Average	**1,210,936**	**1.019**	**(1,350,500)**	**0.973**	**(1,243,452)**	**0.977**	**(1,383,016)**	**0.990**
Hybrid III (Full Indexation Using PEG Custom Input Price Index)								
3 yr	(3,734,844)	0.979	344,838	1.021	(317,536)	1.006	(3,707,542)	1.002
4 yr	3,477,826	1.038	(1,356,728)	0.967	(1,368,777)	0.969	752,321	0.991
Average	**83,628**	**1.010**	**(555,991)**	**0.992**	**(874,075)**	**0.986**	**(1,346,438)**	**0.996**
Hybrid IV (GDPPI)								
3 yr	(4,796,431)	0.971	(866,151)	0.989	(1,099,055)	0.984	(6,761,638)	0.981
4 yr	2,008,485	1.026	(2,861,174)	0.929	(2,381,572)	0.942	(3,234,261)	0.966
Average	**(1,193,828)**	**1.000**	**(1,922,340)**	**0.957**	**(1,778,035)**	**0.962**	**(4,894,203)**	**0.973**
Hybrid V (CPI-U Honolulu)								
3 yr	(3,935,594)	0.974	(635,274)	0.991	(910,013)	0.986	(5,480,881)	0.984
4 yr	2,124,976	1.023	(2,798,426)	0.926	(2,346,533)	0.940	(3,019,984)	0.963
Average	**(727,057)**	**1.000**	**(1,780,472)**	**0.957**	**(1,670,524)**	**0.962**	**(4,178,053)**	**0.973**
Hybrid VI (Global Insight's Summary Electric Utility Materials and Services Price Index [JETOTALMS])								
3 yr	(3,056,535)	0.983	(390,972)	1.001	(629,348)	0.996	(4,076,856)	0.993
4 yr	4,078,414	1.040	(2,316,111)	0.942	(1,833,072)	0.956	(70,769)	0.979
Average	**720,791**	**1.013**	**(1,410,163)**	**0.970**	**(1,266,614)**	**0.975**	**(1,955,986)**	**0.986**
Hybrid VII (HECO's 12 Category Decomposition)								
3 yr	(2,673,010)	0.988	(339,359)	1.004	(577,291)	0.999	(3,589,659)	0.997
4 yr	4,854,095	1.049	(2,153,931)	0.948	(1,650,724)	0.962	1,049,440	0.986
Average	**1,311,928**	**1.020**	**(1,300,015)**	**0.974**	**(1,145,579)**	**0.980**	**(1,133,667)**	**0.991**

[1] Calculations cover only the out (i.e. attrition) years of decoupling plans.

Hybrid 2 (PEG Custom Input Price Index)

This escalator is expected to provide results that are virtually identical to those of Hybrid 1 and does. Its noteworthy eccentricity is its tendency to *over*compensate for labor expenses and *under*compensate for other O&M expenses. This results from the fact that the escalator isn't designed to capture the typical differences in the productivity growth of the two input categories. These distortions cancel out on balance.

Hybrid 3 (Full Indexation Using PEG's Custom Inflation Index)

This escalator does the best job of tracking the O&M expenses of the three companies. There is less *over*compensation of HECO and less *under*compensation of HELCO and MECO. These results are unsurprising inasmuch as this is the only escalator that is customized to capture the cost impact of each company's customer growth.

Hybrids 4 and 5 (GDPPI and CPI-U)

These indexes should yield similar results because their growth trends were quite similar over the 1996-2007 simulation period. Both indexes are almost exactly compensatory for HECO but markedly undercompensatory for HELCO and MECO. The overall compensation is the lowest of all escalators considered. This is not surprising for two reasons. Both indexes underestimated the growth in the prices of electric utility O&M inputs that occurred over the sample period. Additionally, neither index has been customized to capture the special cost challenges posed by HELCO's and MECO's rapid customer growth.

Hybrid 6 (Global Insight Summary Price Index)

This escalator has an impact that is broadly similar to that of Hybrid 1 and Hybrid 2, as we might expect inasmuch as it provides only inflation adjustments and uses a similar mix of Global Insight price indexes. The index is a little overcompensatory for HECO and is uncompensatory for HELCO and MECO. These results are explained by the failure of the index to capture the differential cost challenges posed by different rates of customer growth.

Hybrid 7 (HECO 12 Category Disaggregation)

This escalator yields results that are broadly similar to those Hybrids 1, 2, and 6, as we might expect inasmuch as it provides only inflation adjustments and uses a similar mix of Global Insight price indexes. The escalator is overcompensatory for HECO, a result that reflects in part the fact that it isn't designed to capture the cost impact of HECO's slow output growth. The escalator is uncompensatory for HELCO and MECO. This result reflects in part the fact that the escalator isn't designed to capture the cost impact of HELCO's and MECO's brisk output growth. The escalator is a little uncompensatory on balance for the three companies.

Total Cost Results

Total cost results for the hybrid and formulaic RAMs considered appear in Table 10. The results for the seven hybrid RAMS are expected to be a toned down version of the O&M results. This is what we find. HECO's 12-category disaggregated approach, for instance, recovers 99.1% of O&M expenses and 99.6% of the applicable total cost. This kind of outcome makes sense for two reasons. One is the assumption of perfect foresight for most capital costs. The other is the tendency of taxes to ameliorate the consequences of any under or overcompensation. The full indexation hybrid produces the best results overall.

5.4.2 Formulaic RAMs

Revenue Per Customer Index

The RPC index is the least compensatory of all RAMs considered. Considering all companies together it generates revenue that is only 95.8 % of the applicable total cost during the attrition years.

GDPPI

The inflation only RAM that uses GDPPI is also markedly uncompensatory, generating revenue that is only 96.7% of the applicable total cost on average. It does considerably worse for HELCO and MECO than for HECO because of its failure to capture the cost impact of rapid output growth.

Table 10

FINANCIAL SUFFICIENCY SIMULATION: SUMMARY OF ALL PLANS

	HECO		HELCO		MECO		All Company Total	
	Average Revenue Surplus (Shortfall) [1] [A]	Average Revenue / Cost [1]	Average Revenue Surplus (Shortfall) [1] [B]	Average Revenue / Cost [1]	Average Revenue Surplus (Shortfall) [1] [C]	Average Revenue / Cost [1]	Average Revenue Surplus (Shortfall) [A]+[B]+[C]	Average Revenue / Cost [1]
Hybrid I (PEG Custom Input Price Index)								
3 yr	(3,046,896)	0.994	(430,820)	1.000	(738,702)	0.997	(4,216,418)	0.997
4 yr	5,203,657	1.018	(2,444,078)	0.979	(1,928,708)	0.985	830,871	0.994
Average	**1,321,044**	**1.006**	**(1,496,662)**	**0.989**	**(1,368,705)**	**0.990**	**(1,544,324)**	**0.995**
Hybrid II (PEG 3 Category Decomposition)								
3 yr	(3,023,177)	0.994	(420,765)	1.000	(734,409)	0.997	(4,178,351)	0.997
4 yr	5,197,652	1.018	(2,425,699)	0.979	(1,924,984)	0.985	846,969	0.994
Average	**1,329,027**	**1.006**	**(1,482,201)**	**0.989**	**(1,364,713)**	**0.990**	**(1,517,887)**	**0.995**
Hybrid III (Full Indexation Using PEG Custom Input Price Index)								
3 yr	(4,099,066)	0.991	378,467	1.007	(348,502)	1.000	(4,069,101)	0.999
4 yr	3,816,984	1.014	(1,489,036)	0.987	(1,502,260)	0.988	825,688	0.996
Average	**91,784**	**1.003**	**(610,211)**	**0.996**	**(959,315)**	**0.994**	**(1,477,742)**	**0.998**
Hybrid IV (GDPPI)								
3 yr	(5,264,179)	0.987	(950,618)	0.995	(1,206,235)	0.993	(7,421,033)	0.992
4 yr	2,704,353	1.009	(3,140,196)	0.972	(2,613,823)	0.978	(3,549,666)	0.987
Average	**(1,310,250)**	**0.999**	**(2,109,807)**	**0.983**	**(1,951,429)**	**0.985**	**(5,371,485)**	**0.989**
Hybrid V (CPI-U Honolulu)								
3 yr	(4,319,393)	0.989	(697,226)	0.996	(998,758)	0.993	(6,015,377)	0.993
4 yr	2,332,203	1.008	(3,071,329)	0.971	(2,575,367)	0.978	(3,314,493)	0.986
Average	**(797,960)**	**0.999**	**(1,954,104)**	**0.983**	**(1,833,433)**	**0.985**	**(4,585,497)**	**0.989**
Hybrid VI (Global Insight's Summary Electric Utility Materials and Services Price Index [JETOTALMS])								
3 yr	(3,354,608)	0.992	(429,100)	1.000	(690,723)	0.997	(4,474,431)	0.996
4 yr	4,476,141	1.015	(2,541,978)	0.977	(2,011,833)	0.983	(77,671)	0.992
Average	**791,082**	**1.004**	**(1,547,682)**	**0.988**	**(1,390,134)**	**0.990**	**(2,146,734)**	**0.994**
Hybrid VII (HECO's 12 Category Decomposition)								
3 yr	(2,933,682)	0.994	(372,453)	1.001	(633,588)	0.998	(3,939,723)	0.997
4 yr	5,327,466	1.018	(2,363,982)	0.980	(1,811,702)	0.986	1,151,782	0.994
Average	**1,439,867**	**1.007**	**(1,426,792)**	**0.989**	**(1,257,296)**	**0.991**	**(1,244,220)**	**0.996**
Revenue per Customer Freeze								
3 yr	(16,898,143)	0.954	(1,878,148)	0.985	(4,313,244)	0.964	(23,089,535)	0.967
4 yr	(14,470,961)	0.962	(6,695,948)	0.947	(6,720,736)	0.939	(27,887,645)	0.949
Average	**(15,613,164)**	**0.958**	**(4,428,748)**	**0.965**	**(5,587,799)**	**0.950**	**(25,629,711)**	**0.958**
Inflation Relief Only - GDPPI								
3 yr	(8,867,811)	0.975	(2,372,858)	0.981	(3,708,219)	0.969	(14,948,888)	0.975
4 yr	(3,954,824)	0.990	(7,148,325)	0.944	(5,842,260)	0.946	(16,945,409)	0.960
Average	**(6,266,818)**	**0.983**	**(4,901,047)**	**0.961**	**(4,838,006)**	**0.956**	**(16,005,870)**	**0.967**

[1] Calculations cover only the out (i.e. attrition) years of decoupling plans.

5.4.3 Conclusions

The simulations point to a few key conclusions.

- There is a clear tradeoff between design complexity and the accuracy of RAM results. RAMs are more accurate to the extent that they capture the cost impact of the diverse cost drivers that utilities face.
- Custom inflation measures are more accurate than macroeconomic measures.
- Differences in customer growth should be recognized, but this requires the choice of a productivity target.
- Summary input price indexes yield the same result as disaggregated approaches but do not overcompensate for salaries and wages or undercompensate for other O&M expenses.

APPENDIX

A. CREDENTIALS OF MARK NEWTON LOWRY

Dr. Lowry, the principle investigator for this project, is a partner of PEG and manages its office in Madison WI. His duties include the supervision of statistical cost research, the design of alternative regulation (Altreg) plans, and expert witness testimony. He has for many years been the chief advisor on Altreg to the Edison Electric Institute. His practice is international in scope and has to date included projects in seven countries. He has testified numerous times on Altreg and other issues. Venues for his testimony have included California, Georgia, Hawaii, Illinois, Kentucky, Maine, Massachusetts, Missouri, Oklahoma, New York, Vermont, Alberta, British Columbia, Ontario, and Quebec.

Revenue decoupling is one of Dr. Lowry's specialties. He has provided supportive testimony in proceedings leading to the approval of ten revenue adjustment mechanisms, including mechanisms for BC Gas (d/b/a Terasen Gas), Central Vermont Public Service, Enbridge Gas Distribution, Southern California Gas, and San Diego Gas and Electric. Clients that he has advised on decoupling include, additionally, National Grid, Nicor Gas, and PG&E. He has published two articles that discuss decoupling issues.

Before joining PEG Dr. Lowry worked for several years at Christensen Associates in Madison, first as a senior economist and later as a Vice President and director of that company's Regulatory Strategy practice. His career has also included work as an academic economist. He has served as an Assistant Professor of Mineral Economics at the Pennsylvania State University and as a visiting professor at l'Ecole des Hautes Etudes Commerciales in Montreal. His academic research and teaching stressed the use of mathematical theory and econometrics in industry analysis.

In total, Dr. Lowry has two decades of experience as a practicing economist and fifteen years of experience in the field of utility regulation. He holds a B.A. in Ibero-American studies and a Ph.D. in applied economics from the University of Wisconsin. He has served as a referee for several scholarly journals and has an extensive record of professional publications and public appearances.

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Hawaiian Electric [illegible], Inc
Decoupling - Proposal (G.I. O&M ONLY - NO CHANGE IN RATE BASE)
Results of Operations
Based on 2009 Test Year
($ Thousands)

	Current Effective Rates	Additional Amount	Revenue Requirements to Produce 8.81% Return on Average Rate Base	2009 Nominal Amount (N.1)	2009 BAU Amount	2009 1 + Index	Notes	2010 BAU * Index Amount	2010 Nominal Amount (N.1)	2010 TOTAL RAM Amount	Notes	2010 Nominal Amount	2011 BAU Amount	2011 1 + Index	Notes	2011 BAU * Index Amount	2011 Nominal Amount	2011 TOTAL RAM Amount	Notes
Electric Sales Revenue	1,861,751	99,913	1,961,664					0		1,967,718	N.11							1,973,111	N.11
Other Operating Revenue	4,487	122	4,609	4,609	0			0	4,609	4,609		4,609					4,609	4,609	
Gain on Sale of Land	615		615	615	0	100.0%	N.2	0	615	615		615	0	100.0%	N.2	0	615	615	
TOTAL OPERATING REVENUES	1,866,853	100,035	1,966,888	5,224	0			0		1,972,942		5,224	0			0		1,978,335	
Fuel	816,654		816,654	816,654	0	100.0%	N.2	0	816,654	816,654		816,654	0	100.0%	N.2	0	816,654	816,654	
Purchased Power	477,055		477,055	477,055	0	100.0%	N.2	0	477,055	477,055		477,055	0	100.0%	N.2	0	477,055	477,055	
Production	82,423		82,423																
Production Labor *			33,819		33,819	104.4%	N.3a	35,307		35,307		0	35,307	102.4%	N.3a	36,154		36,154	
Production NonLabor *			48,604	0	48,604	100.8%	N.3b	48,993	0	48,993		0	48,993	101.7%	N.3b	49,826	0	49,826	
Transmission	13,930		13,930																
Transmission Labor *			4,951		4,951	104.4%	N.3a	5,169		5,169		0	5,169	102.4%	N.3a	5,293		5,293	
Transmission NonLabor *			8,979		8,979	101.4%	N.4	9,104		9,104		0	9,104	101.3%	N.4	9,223		9,223	
Distribution	30,515		30,515																
Distribution Labor *			12,474		12,474	104.4%	N.3a	13,023		13,023		0	13,023	102.4%	N.3a	13,336		13,336	
Distribution NonLabor *			18,042	0	18,041	99.9%	N.5	18,023	0	18,023		0	18,023	101.0%	N.5	18,203	0	18,203	
Customer Accounts	16,297		16,297																
Customer Accounts Labor *			7,729		7,729	102.4%	N.3a	7,915		7,915		0	7,915	102.2%	N.3a	8,089		8,089	
Customer Accounts NonLabor *			8,568	0	8,568	102.1%	N.6	8,748	0	8,748		0	8,748	101.5%	N.6	8,879	0	8,879	
Allowance for Uncoll. Accounts	1,339	72	1,411		1,411	101.5%	N.13	1,432		1,432		0	1,432	101.3%	N.13	1,450		1,450	
Customer Service	6,997		6,997																
Customer Service Labor *			964		964	102.4%	N.3a	987		987		0	987	102.2%	N.3a	1,009		1,009	
Customer Service NonLabor *			6,033		6,033	101.4%	N.7	6,117		6,117		0	6,117	101.3%	N.7	6,197		6,197	
Administration & General	77,863		77,863							0		0						0	
Admin & Gen Labor *			21,199		21,199	103.0%	N.3a	21,835		21,835		0	21,835	102.9%	N.3a	22,468		22,468	
Admin & Gen NonLabor *			56,664	19,098	37,566	103.5%	N.8	38,881	19,098	57,979		19,098	38,881	103.1%	N.8	40,086	19,098	59,184	
Operation and Maintenance	1,523,073	72	1,523,145	1,312,807	210,338			215,534		1,528,341		1,312,807	215,534			220,213	1,312,807	1,533,020	
Depreciation & Amortization	82,966		82,966	na	na			na		82,966	N.12	na	na			na		82,966	N.12
Amortization of State ITC	(1,453)		(1,453)		1,453	100.0%	N.12	-1,453		-1,453		0	-1,453	100.0%	N.12	-1,453		-1,453	N.12
Taxes Other Than Income	172,913	8,879	181,792	na	na			na		182,609	N.14	na	na			na		183,277	N.14
Interest on Customer Deposits	479		479		479	108.5%	N.15	520		520		0	520	108.5%	N.15	564		564	
Income Taxes	20,251	35,441	55,692	na	na			na		55,692		na	na			na		55,692	
TOTAL OPERATING EXPENSES	1,798,229	44,392	1,842,621	1,312,807	209,364			214,601		1,848,674		1,312,807	214,601			219,324		1,854,066	
													0			0		0	
OPERATING INCOME	68,624	55,643	124,267	na	na			na		124,267	N.10	na	na			0		124,267	N.10
								0		0			0			0		0	
AVERAGE RATE BASE	1,411,417	(900)	1,410,517	na	na			na		1,410,517	N.9	na	na			na		1,410,517	N.9
RATE OF RETURN ON AVERAGE RATE BASE	4.86%		8.81%							8.81%								8.81%	
REVENUE ADJUSTMENT (DIFFERENCE IN TOTAL OPERATING REVENUES)										$6,054								$5,393	

* Allocated Labor and Nonlabor of total O&M expenses based on 2009 Budget as provided in HECO-WP-101(A) in the 2009 Rate Case

N.1 See "Nominal" [illegible] Worksheet
N.2 No escalator u[illegible]
N.3a Global Insight, Power Planner, Third-Quarter 2008, p. 60, "Table A30 Utility Price & Wage Indicators"
N.3b Global Insight, Power Planner, Third-Quarter 2008, p. 48, "Steam Production Plant JEPOMMS"
N.4 Global Insight, Power Planner, Third-Quarter 2008, p. 48, "Transmission Plant JETOMMS"
N.5 Global Insight, Power Planner, Third-Quarter 2008, p. 48, "Distribution Plant JEDOMMS"
N.6 Global Insight, Power Planner, Third-Quarter 2008, p. 48, "Customer Accounts, JECAOMS"
N.7 Global Insight, Power Planner, Third-Quarter 2008, p. 48, "Customer Service and Information JECSIOMS"
N.8 Global Insight, Power Planner, Third-Quarter 2008, p. 48, "Administrative and General, JEADGOMMS"
N.9 No change in rate base
N.10 Based on 2009 TY RORB = 8.81%
N.11 (Total Operating Expenses less revenue taxes+Operating Income)/(1-PUC & PSC & Franchise Tax rates-Uncoll Factor) less Other Operating revenue & Gain on Sale of Land
N.12 Index based on growth rate of average rate base
N.13 Based on growth of O&M Expenses and Operating Income
N.14 See "Taxes" Tab in Worksheet
N.15 Based on growth rate submitted for 2009 Rate Case (Rate Case Update, HECO T-9, p.7)

Total Labor in Test Year		
2009	81,136.4	
2010	84,235.7	103.82%
2011	86,340.8	102.51%
Total NonLabor in Test Year (excluding Fuel & Purchase Power expense)		
2009	146,888.6	
2010	148,964.3	101.41%
2011	151,511.8	101.71%
Total O&M (excluding Fuel & Purchase Power expense)		
2009	228,025.0	
2010	233,200.0	102.27%
2011	237,860.6	102.00%
Total Operating Income		
2009	124,267.0	
2010	124,266.5	100.00%
2011	124,266.5	100.00%
Total O&M Expenses (excluding Fuel & Purchase Power expense) & Operating Income		
2009	352,792.0	
2010	357,466.6	101.47%
2011	362,127.1	101.30%

Hawaiian Electric Company, Inc.

CIP (Full Cost w/o Wind Studies & Sales Red) at Curr Eff Rates
COMPOSITE EMBEDDED COST OF CAPITAL
Estimated 2009 Average

	A	B	C	D
	Capitalization			
	Amount in Thousands	Percent of Total	Earnings Reqmts	Weighted Earnings Reqmts (B) x (C)
Short-Term Debt	21,951	1.49	3.25%	0.049%
Long-Term Debt	561,940	38.27	5.75%	2.200%
Hybrid Securities	27,775	1.89	7.41%	0.140%
Preferred Stock	59,496	4.05	7.62%	0.309%
Common Equity	797,308	54.30	11.25%	6.108%
Total	1,468,470	100.00		
Estimated Composite Cost of Capital				8.806%
			or	8.81%

Hawaiian Electric Company, Inc.

CIP (Full Cost w/o Wind Studies & Sales Red) at Curr Eff Rates
WORKING CASH ITEMS
2009
($ Thousands)

	A COLLECTION LAG (DAYS)	B PAYMENT LAG (DAYS)	C NET COLLECTION LAG (DAYS) (A - B)	D ANNUAL AMOUNT
ITEMS REQUIRING WORKING CASH				
Fuel Oil Purchases	37	17	20	809,058
O&M Labor	37	11	26	101,730
O&M Nonlabor	37	30	7	128,292
ITEMS THAT PROVIDE WORKING CASH				
Revenue Taxes	37	66	(29)	165,584
Income Taxes-Curr Eff Rates	37	39	(2)	14,307
Income Taxes-Proposed Rates	37	39	(2)	49,748
Purchased Power	37	37	0	477,055

	E AVERAGE DAILY AMOUNT (D/365)	F WORKING CASH (CURR EFF RATES) (C X E)	G AVERAGE DAILY AMOUNT (PROPOSED)	H WORKING CASH (PROPOSED RATES) (C X G)
ITEMS REQUIRING WORKING CASH				
Fuel Oil Purchases	2,217	44,332	2,217	44,332
O&M Labor	279	7,247	279	7,247
O&M Nonlabor	351	2,460	351	2,460
ITEMS THAT PROVIDE WORKING CASH				
Purchased Power	1,307	0	1,307	0
Revenue Taxes	454	(13,156)	478	(13,861)
Income Taxes-Curr Eff Rates	39	(78)		
Income Taxes-Proposed Rates	136	-	136	(273)
Total		40,805		39,905
Change in Working Cash				(900)

Hawaiian Electric Company, Inc.

CIP (Full Cost w/o Wind Studies & Sales Red) at Curr Eff Rates
COMPUTATION OF INCOME TAX EXPENSE
2009
($ Thousands)

	Current Effective Rates	Adjustment	At Proposed Rates
Operating Revenues	1,866,853	100,035	1,966,888
Operating Expenses:			
Fuel Oil and Purchased Power	1,293,709		1,293,709
Other Operation & Maintenance Expense	229,364	72	229,436
Depreciation	82,966		82,966
Amortization of State ITC	(1,453)		(1,453)
Taxes Other than Income	172,913	8,879	181,792
Interest on Customer Deposits	479		479
Total Operating Expenses	1,777,978	8,951	1,786,929
Operating Income Before Income Taxes	88,875	91,084	179,959
Tax Adjustments:			
Interest Expense	(33,697)		(33,697)
Meals and Entertainment	78		78
	(33,619)	0	(33,619)
Taxable Income at Ordinary Rates	55,256	91,084	146,340
Income Tax Exp at Ordinary Rates	21,500	35,441	56,941
Tax Benefit of Domestic Production Activities Deduction	1,226		1,226
Tax Effect of Deductible Preferred Stock Dividends	23		23
TOTAL INCOME TAX EXPENSE	20,251	35,441	55,692

Hawaiian Electric Company, Inc.

CIP (Full Cost w/o Wind Studies & Sales Red) at Curr Eff Rates
COMPUTATION OF TAXES OTHER THAN INCOME TAX
2009
($ Thousands)

	Rate	Current Effective Rates	Adjustment	At Proposed Rates
Electric Sales Revenue		1,861,751	99,913	1,961,664
Other Operating Revenue		4,487	122	4,609
Operating Revenues		1,866,238	100,035	1,966,273
Public Service Tax	5.885%	109,749	5,883	115,632
PUC Fees	0.500%	9,324	500	9,824
Franchise Tax	2.500%	46,510	2,496	49,006
Payroll Tax		7,330		7,330
TOTAL TAXES OTHER THAN INCOME TAX		172,913	8,879	181,792

Hawaiian Electric Company, Inc.

CIP (Full Cost w/o Wind Studies & Sales Red) at Curr Eff Rates
CALCULATIONS OF REVENUE REQUIREMENTS
2009
($ Thousands)

OPERATING INCOME AT CURRENT EFFECTIVE RATES:		
Operating Revenues		1,866,853
Fuel and Purchased Power Expenses		1,293,709
Other O&M Expenses		229,364
Depreciation & Amortization Expense		82,966
Amortization of State ITC		(1,453)
Taxes Other than Income		172,913
Interest on Customer Deposits		479
Income Taxes		20,251
Total Operating Expenses		1,798,229
OPERATING INCOME AT CURRENT EFFECTIVE RATES		68,624
CALCULATIONS OF REVENUE REQUIREMENTS:		
OPERATING INCOME		
Rate Base at Proposed Rates		1,410,517
Proposed Rate of Return on Rate Base	x	8.81%
Operating Income		124,267
Less: Operating Income at Current Effective Rate		68,624
INCREASE IN OPERATING INCOME		55,643
OPERATING REVENUES:		
Increase in Operating Income		55,643
Operating Income Divisor	(divided by)	0.55624
INCREASE IN OPERATING REVENUES		100,035
Increase in Electric Sales Revenue		99,913
Other Operating Revenue Rate	x	0.122%
Increase in Other Operating Revenues		122
		100,035

Hawaiian Electric Company, Inc.

CIP (Full Cost w/o Wind Studies & Sales Red) at Curr Eff Rates
CALCULATIONS OF REVENUE REQUIREMENTS
2009
($ Thousands)

BAD DEBT:		
Increase in Electric Revenues		99,913
Bad Debt Rate	x	0.0007
INCREASE IN BAD DEBT EXPENSE		72
REVENUE TAX:		
Increase in Operating Revenues		100,035
Less: Increase in Bad Debt Expense		(72)
		99,963
PSC Tax & PUC Fees Rate	x	6.385%
		6,383
Increase in Electric Revenues		99,913
Less: Increase in Bad Debt Expense		(72)
		99,841
Franchise Tax Rate	x	2.500%
		2,496
INCREASE IN REVENUE TAX		8,879
INCOME TAX:		
Increase in Operating Revenues		100,035
Effective Income Tax Rate after considering revenue tax & bad debt	x	35.428%
INCREASE IN INCOME TAX		35,441
INCREASE IN OPERATING INCOME (check)		55,643

Hawaiian Electric Company, Inc.

CIP (Full Cost w/o Wind Studies & Sales Red) at Curr Eff Rates
CALCULATIONS OF REVENUE REQUIREMENTS
2009
($ Thousands)

CHANGE IN RATE BASE:

	A EXPENSE AMOUNT	B AVERAGE DAILY AMOUNT (A/365)	C NET COLLECTION LAG (DAYS)	D WORKING CASH REQMT (B)x(C)
Increase in Revenue Tax	8,879	24	(29)	(705)
Income Tax at Curr Eff rate	14,307	39	(2)	78
Income Tax at proposed rate	49,748	136	(2)	(273)
CHANGE IN RATE BASE - WORKING CASH				(900)
Rate Base at Current Effective Rates				1,411,417
PROPOSED RATE BASE				1,410,517
Operating Income at Current Effective Rates				68,624
Increase in Operating Income				55,643
OPERATING INCOME AT PROPOSED RATES				124,267
PROPOSED RATE OF RETURN ON RATE BASE (check)				8.81%

Decoupling - Proposal
Results of Operations
Based on 2009 Test Year
($ Thousands)

	Revenue Requirements to Produce 8.81% Return on Average Rate Base	Nominal Amount in TY 2009	2010 Nominal Amount	2011 Nominal Amount	2012 Nominal Amount	Comments
Electric Sales Revenue	1,961,664					
Other Operating Revenue	4,609	4,609	4,609	4,609	4,609	Updated HECO-304 (Update, T-3, Att. 4, p. 1
Gain on Sale of Land	615	615	615	615	615	
TOTAL OPERATING REVENUES	1,966,888	5,224	5,224	5,224	5,224	
Fuel	816,654	816,654	816,654	816,654		ECAC Recovery - amount in base rates
Purchased Power	477,055	477,055	477,055	477,055		ECAC Recovery - amount in base rates
Production	82,423					
Transmission	13,930					
Distribution	30,515					
Customer Accounts	16,297					
Allowance for Uncoll. Accounts	1,411					
Customer Service	6,997					
Administration & General	77,863					
	na					
	na					
	na					
	na	14,076	14,076	14,076		Nominal Tab, Attachment 1
	na	5,022	5,022	5,022		Nominal Tab, Attachment 1
A&G Total Nominal Amounts		19,098	19,098	19,098		
Operation and Maintenance/Total Nominal Amounts	1,523,145	1,312,807	1,312,807	1,312,807		

DOCKET NO. 2008-0274
ATTACHMENT 5A

Hawaiian Electric Company, Inc.

CIP (Full Cost w/o Wind Studies & Sales Red) at Curr Eff Rates
SUPPORT WORKSHEET

		2009	2010	2011
REVENUE TAX				
Public Service Tax				
Electric Sales Revenues		1,861,751	1,967,717.9	1,973,110.6
Other Operating Revenues		4,487	4,609.0	4,609.0
Less: Bad Debt Expense		(1,339)	(1,431.7)	(1,450.4)
Operating Revenues subject to PSC Tax		1,864,899	1,970,895	1,976,269
Public Service Tax Rate	x	5.885%	5.885%	5.885%
Total PSC Tax		109,749	115,987	116,303
PUC Fees				
Electric Sales Revenues		1,861,751	1,967,717.9	1,973,110.6
Other Operating Revenues		4,487	4,609.0	4,609.0
Less: Bad Debt Expense		(1,339)	(1,431.7)	(1,450.4)
Operating Revenues subject to PSC Tax		1,864,899	1,970,895	1,976,269
PUC Tax Rate	x	0.500%	0.500%	0.500%
Total PUC Tax		9,324	9,854	9,881
Franchise Tax				
Electric Sales Revenues		1,861,751	1,967,717.9	1,973,110.6
Less: Bad Debt Expense		(1,339)	(1,431.7)	(1,450.4)
		1,860,412	1,966,286	1,971,660
Franchise Tax Rate	x	2.500%	2.500%	2.500%
Total Franchise Tax		46,510	49,157	49,292
TOTAL REVENUE TAX		165,584	174,999	175,476

Maui Electric Company, Limited (MECO)

Global Insights O&M Forecast Only
Rate Case -2007 Test Year - Probable Entitlement
Estimated 2006 Rate Case Average

Capitalization

	A	B	C	D
	Amount in Thousands	Percent of Total	Earnings Reqmts	Weighted Earnings Reqmts (B) x (C)
Short-Term Debt	4,750	1.27	5.00%	0.063%
Revenue Bond	150,585	40.15	6.11%	2.453%
Hybrid Securities	9,192	2.45	7.47%	0.183%
Preferred Stock	4,693	1.25	8.34%	0.104%
Common Equity	205,882	54.89	10.70%	5.873%
Total	375,102	100.00		
Estimated Composite Cost of Capital				8.676%
			or	8.68%

Hawaii Electric Light Company, Inc. (HELCO)

Global Insights O&M Only
Rate Case -2006 Test Year - Settlement Results of Operatic
Estimated 2006 Rate Case Average

	A	B	C	D
	Capitalization			
	Amount in Thousands	Percent of Total	Earnings Reqmts	Weighted Earnings Reqmts (B) x (C)
Short-Term Debt	49,550	13.24	5.00%	0.662%
Revenue Bond	117,408	31.37	5.92%	1.857%
Hybrid Securities	9,152	2.45	7.50%	0.183%
Preferred Stock	6,563	1.75	8.37%	0.147%
Common Equity	191,544	51.19	10.70%	5.477%
Total	374,217	100.00		
Estimated Composite Cost of Capital				8.326%
			or	8.33%

Hawaiian Electric Company, Inc.

CIP (Full Cost w/o Wind Studies & Sales Red) at Curr Eff Rates
COMPOSITE EMBEDDED COST OF CAPITAL
Estimated 2009 Average

	A	B	C	D
	Capitalization			
	Amount in Thousands	Percent of Total	Earnings Reqmts	Weighted Earnings Reqmts (B) x (C)
Short-Term Debt	21,951	1.49	3.25%	0.049%
Long-Term Debt	561,940	38.27	5.75%	2.200%
Hybrid Securities	27,775	1.89	7.41%	0.140%
Preferred Stock	59,496	4.05	7.62%	0.309%
Common Equity	797,308	54.30	11.25%	6.108%
Total	1,468,470	100.00		
Estimated Composite Cost of Capital				8.806%
			or	8.81%

Hawaiian Electric Company, Inc.

CIP (Full Cost w/o Wind Studies & Sales Red) at Curr Eff Rates
WORKING CASH ITEMS
2009
($ Thousands)

	A COLLECTION LAG (DAYS)	B PAYMENT LAG (DAYS)	C NET COLLECTION LAG (DAYS) (A - B)	D ANNUAL AMOUNT
ITEMS REQUIRING WORKING CASH				
Fuel Oil Purchases	37	17	20	809,058
O&M Labor	37	11	26	101,730
O&M Nonlabor	37	30	7	128,292
ITEMS THAT PROVIDE WORKING CASH				
Revenue Taxes	37	66	(29)	165,584
Income Taxes-Curr Eff Rates	37	39	(2)	14,307
Income Taxes-Proposed Rates	37	39	(2)	49,748
Purchased Power	37	37	0	477,055

	E AVERAGE DAILY AMOUNT (D/365)	F WORKING CASH (CURR EFF RATES) (C X E)	G AVERAGE DAILY AMOUNT (PROPOSED)	H WORKING CASH (PROPOSED RATES) (C X G)
ITEMS REQUIRING WORKING CASH				
Fuel Oil Purchases	2,217	44,332	2,217	44,332
O&M Labor	279	7,247	279	7,247
O&M Nonlabor	351	2,460	351	2,460
ITEMS THAT PROVIDE WORKING CASH				
Purchased Power	1,307	0	1,307	0
Revenue Taxes	454	(13,156)	478	(13,861)
Income Taxes-Curr Eff Rates	39	(78)		
Income Taxes-Proposed Rates	136	-	136	(273)
Total		40,805		39,905
Change in Working Cash				(900)

Hawaiian Electric Company, Inc.

CIP (Full Cost w/o Wind Studies & Sales Red) at Curr Eff Rates
COMPUTATION OF INCOME TAX EXPENSE
2009
($ Thousands)

	Current Effective Rates	Adjustment	At Proposed Rates
Operating Revenues	1,866,853	100,035	1,966,888
Operating Expenses:			
Fuel Oil and Purchased Power	1,293,709		1,293,709
Other Operation & Maintenance Expense	229,364	72	229,436
Depreciation	82,966		82,966
Amortization of State ITC	(1,453)		(1,453)
Taxes Other than Income	172,913	8,879	181,792
Interest on Customer Deposits	479		479
Total Operating Expenses	1,777,978	8,951	1,786,929
Operating Income Before Income Taxes	88,875	91,084	179,959
Tax Adjustments:			
Interest Expense	(33,697)		(33,697)
Meals and Entertainment	78		78
	(33,619)	0	(33,619)
Taxable Income at Ordinary Rates	55,256	91,084	146,340
Income Tax Exp at Ordinary Rates	21,500	35,441	56,941
Tax Benefit of Domestic Production Activities Deduction	1,226		1,226
Tax Effect of Deductible Preferred Stock Dividends	23		23
TOTAL INCOME TAX EXPENSE	20,251	35,441	55,692

Hawaiian Electric Company, Inc.

CIP (Full Cost w/o Wind Studies & Sales Red) at Curr Eff Rates
COMPUTATION OF TAXES OTHER THAN INCOME TAX
2009
($ Thousands)

	Rate	Current Effective Rates	Adjustment	At Proposed Rates
Electric Sales Revenue		1,861,751	99,913	1,961,664
Other Operating Revenue		4,487	122	4,609
Operating Revenues		1,866,238	100,035	1,966,273
Public Service Tax	5.885%	109,749	5,883	115,632
PUC Fees	0.500%	9,324	500	9,824
Franchise Tax	2.500%	46,510	2,496	49,006
Payroll Tax		7,330		7,330
TOTAL TAXES OTHER THAN INCOME TAX		172,913	8,879	181,792

Hawaiian Electric Company, Inc.

CIP (Full Cost w/o Wind Studies & Sales Red) at Curr Eff Rates
CALCULATIONS OF REVENUE REQUIREMENTS
2009
($ Thousands)

OPERATING INCOME AT CURRENT EFFECTIVE RATES:		
Operating Revenues		1,866,853
Fuel and Purchased Power Expenses		1,293,709
Other O&M Expenses		229,364
Depreciation & Amortization Expense		82,966
Amortization of State ITC		(1,453)
Taxes Other than Income		172,913
Interest on Customer Deposits		479
Income Taxes		20,251
Total Operating Expenses		1,798,229
OPERATING INCOME AT CURRENT EFFECTIVE RATES		68,624
CALCULATIONS OF REVENUE REQUIREMENTS:		
OPERATING INCOME		
Rate Base at Proposed Rates		1,410,517
Proposed Rate of Return on Rate Base	x	8.81%
Operating Income		124,267
Less: Operating Income at Current Effective Rate		68,624
INCREASE IN OPERATING INCOME		55,643
OPERATING REVENUES:		
Increase in Operating Income		55,643
Operating Income Divisor	(divided by)	0.55624
INCREASE IN OPERATING REVENUES		100,035
Increase in Electric Sales Revenue		99,913
Other Operating Revenue Rate	x	0.122%
Increase in Other Operating Revenues		122
		100,035

Hawaiian Electric Company, Inc.

CIP (Full Cost w/o Wind Studies & Sales Red) at Curr Eff Rates
CALCULATIONS OF REVENUE REQUIREMENTS
2009
($ Thousands)

BAD DEBT:		
Increase in Electric Revenues		99,913
Bad Debt Rate	x	0.0007
INCREASE IN BAD DEBT EXPENSE		72
REVENUE TAX:		
Increase in Operating Revenues		100,035
Less: Increase in Bad Debt Expense		(72)
		99,963
PSC Tax & PUC Fees Rate	x	6.385%
		6,383
Increase in Electric Revenues		99,913
Less: Increase in Bad Debt Expense		(72)
		99,841
Franchise Tax Rate	x	2.500%
		2,496
INCREASE IN REVENUE TAX		8,879
INCOME TAX:		
Increase in Operating Revenues		100,035
Effective Income Tax Rate after considering revenue tax & bad debt	x	35.428%
INCREASE IN INCOME TAX		35,441
INCREASE IN OPERATING INCOME (check)		55,643

Hawaiian Electric Company, Inc.

CIP (Full Cost w/o Wind Studies & Sales Red) at Curr Eff Rates
CALCULATIONS OF REVENUE REQUIREMENTS
2009
($ Thousands)

CHANGE IN RATE BASE:

	A EXPENSE AMOUNT	B AVERAGE DAILY AMOUNT (A/365)	C NET COLLECTION LAG (DAYS)	D WORKING CASH REQMT (B)x(C)
Increase in Revenue Tax	8,879	24	(29)	(705)
Income Tax at Curr Eff rate	14,307	39	(2)	78
Income Tax at proposed rate	49,748	136	(2)	(273)
CHANGE IN RATE BASE - WORKING CASH				(900)
Rate Base at Current Effective Rates				1,411,417
PROPOSED RATE BASE				1,410,517
Operating Income at Current Effective Rates				68,624
Increase in Operating Income				55,643
OPERATING INCOME AT PROPOSED RATES				124,267
PROPOSED RATE OF RETURN ON RATE BASE (check)				8.81%

Decoupling - Proposal
Results of Operations
Based on 2009 Test Year
($ Thousands)

	Revenue Requirements to Produce 8.81% Return on Average Rate Base	Nominal Amount in TY 2009	2010 Nominal Amount	2011 Nominal Amount	2012 Nominal Amount	Comments
Electric Sales Revenue	1,961,664					
Other Operating Revenue	4,609					
Gain on Sale of Land	615					
TOTAL OPERATING REVENUES	1,966,888	0	0	0	0	
Fuel	816,654	816,654	816,654	816,654		ECAC Recovery - amount in base rates
Purchased Power	477,055	477,055	477,055	477,055		ECAC Recovery - amount in base rates
Production	82,423					
Transmission	13,930					
Distribution	30,515					
Customer Accounts	16,297					
Allowance for Uncoll. Accounts	1,411					
Customer Service	6,997					
Administration & General	77,863					
	na					
	na					
	na					
	na	14,076	14,076	14,076		Nominal Tab, Attachment 1
	na	5,022	5,022	5,022		Nominal Tab, Attachment 1
A&G Total Nominal Amounts		19,098	19,098	19,098		
Operation and Maintenance/Total Nominal Amounts	1,523,145	1,312,807	1,312,807	1,312,807		

Maui Electric Company, Limited (MECO)

Rate Base Forecast Only
Rate Case -2007 Test Year - Probable Entitlement
Estimated 2006 Rate Case Average

	A	B	C	D
	Capitalization			
	Amount in Thousands	Percent of Total	Earnings Reqmts	Weighted Earnings Reqmts (B) x (C)
Short-Term Debt	4,750	1.27	5.00%	0.063%
Revenue Bond	150,585	40.15	6.11%	2.453%
Hybrid Securities	9,192	2.45	7.47%	0.183%
Preferred Stock	4,693	1.25	8.34%	0.104%
Common Equity	205,882	54.89	10.70%	5.873%
Total	375,102	100.00		
Estimated Composite Cost of Capital				8.676%
			or	8.68%

Hawaii Electric Light Company, Inc. (HELCO)

Rate Base Forecast Only
Rate Case -2006 Test Year - Settlement Results of Operations
Estimated 2006 Rate Case Average

	A	B	C	D
	Capitalization			
	Amount in Thousands	Percent of Total	Earnings Reqmts	Weighted Earnings Reqmts (B) x (C)
Short-Term Debt	49,550	13.24	5.00%	0.662%
Revenue Bond	117,408	31.37	5.92%	1.857%
Hybrid Securities	9,152	2.45	7.50%	0.183%
Preferred Stock	6,563	1.75	8.37%	0.147%
Common Equity	191,544	51.19	10.70%	5.477%
Total	374,217	100.00		
Estimated Composite Cost of Capital				8.326%
			or	8.33%

Hawaiian El[illegible] Company, Inc
Decoupling - Proposal (No Change to O&M - Regression Analysis Results Applied to RATE BASE)
Results of Operations
Based on 2009 Test Year
($ Thousands)
NOTE: NO SIGNIFICANT PROJECTS ADDED IN

	Current Effective Rates	Additional Amount	Revenue Requirements to Produce 8.81% Return on Average Rate Base	2009 Nominal Amount (N.1)	2009 BAU Amount	2009 1 + Index	Notes	2010 BAU + Index Amount	2010 Nominal Amount (N.1)	2010 TOTAL RAM Amount	Notes	2010 Nominal Amount	2011 BAU Amount	2011 1 + Index	Notes	2011 BAU + Index Amount	2011 Nominal Amount	2011 TOTAL RAM Amount	Notes
Electric Sales Revenue	1,861,751	99,913	1,961,664					0		1,967,975	N.11							1,974,268	N.11
Other Operating Revenue	4,487	122	4,609	4,609	0			0	4,609	4,609		4,609					4,609	4,609	
Gain on Sale of Land	615		615	615	0	100.0%	N.2	0	615	615		615	0	100 0%	N 2	0	615	615	
TOTAL OPERATING REVENUES	1,866,853	100,035	1,966,888	5,224	0			0		1,973,199		5,224	0			0		1,979,492	
Fuel	816,654		816,654	816,654	0	100.0%	N.2	0	816,654	816,654		816,654	0	100.0%	N.2	0	816,654	816,654	
Purchased Power	477,055		477,055	477,055	0	100.0%	N.2	0	477,055	477,055		477,055	0	100.0%	N.2	0	477,055	477,055	
Production	82,423		82,423																
Production Labor *			33,819		33,819	100.0%	N.2	33,819		33,819		0	33,819	100.0%	N.2	33,819		33,819	
Production NonLabor *			48,604	0	48,604	100.0%	N.2	48,604	0	48,604		0	48,604	100.0%	N 2	48,604	0	48,604	
Transmission	13,930		13,930																
Transmission Labor *			4,951		4,951	100.0%	N.2	4,951		4,951		0	4,951	100.0%	N.2	4,951		4,951	
Transmission NonLabor *			8,979		8,979	100 0%	N.2	8,979		8,979		0	8,979	100.0%	N.2	8,979		8,979	
Distribution	30,515		30,515																
Distribution Labor *			12,474		12,474	100.0%	N.2	12,474		12,474		0	12,474	100.0%	N.2	12,474		12,474	
Distribution NonLabor *			18,041	0	18,041	100.0%	N.2	18,041	0	18,041		0	18,041	100.0%	N.2	18,041	0	18,041	
Customer Accounts	16,297		16,297																
Customer Accounts Labor *			7,729		7,729	100.0%	N.2	7,729		7,729		0	7,729	100.0%	N.2	7,729		7,729	
Customer Accounts NonLabor *			8,568	0	8,568	100.0%	N 2	8,568	0	8,568		0	8,568	100 0%	N.2	8,568	0	8,568	
Allowance for Uncoll. Accounts	1,339	72	1,411		1,411	100.8%	N.13	1,422		1,422		0	1,422	100.8%	N.13	1,433		1,433	
Customer Service	6,997		6,997																
Customer Service Labor *			964		964	100.0%	N.2	964		964		0	964	100.0%	N.2	964		964	
Customer Service NonLabor *			6,033		6,033	100.0%	N 2	6,033		6,033		0	6,033	100 0%	N 2	6,033		6,033	
Administration & General	77,863		77,863							0		0						0	
Admin & Gen Labor *			21,199		21,199	100 0%	N 2	21,199		21,199		0	21,199	100.0%	N.2	21,199		21,199	
Admin & Gen NonLabor *			56,664	19,098	37,566	100 0%	N.2	37,566	19,098	56,664		19,098	37,566	100 0%	N.2	37,566	19,098	56,664	
Operation and Maintenance	1,523,073	72	1,523,145	1,312,807	210,338			210,349		1,523,156		1,312,807	210,349			210,360	1,312,807	1,523,167	
Depreciation & Amortization	82,966		82,966	na	na			na		84,768	N 12	na	na			na		86,570	N.12
Amortization of State ITC	(1,453)		(1,453)		-1,453	102.2%	N 12	-1,485		-1,485		0	-1,485	102 1%	N 12	-1,516		-1,516	N.12
Taxes Other Than Income	172,913	8,879	181,792	na	na			na		182,353	N 14	na	na			na		182,911	N.14
Interest on Customer Deposits	479		479		479	108 5%	N.15	520		520		0	520	108 5%	N.15	564		564	
Income Taxes	20,251	35,441	55,692	na	na			na		56,901		na	na			na		58,111	
TOTAL OPERATING EXPENSES	1,798,229	44,392	1,842,621	1,312,807	209,364			209,384		1,846,213		1,312,807	209,384			209,408		1,849,407	
													0			0		0	
OPERATING INCOME	*68,624*	55,643	*124,267*	*na*	*na*			*na*		*126,966*	*N.10*	*na*	*na*			*0*		*129,665*	*N.10*
								0		0			0			0		0	
AVERAGE RATE BASE	*1,411,417*	*(900)*	*1,410,517*	na	*na*			*na*		1,441,355	*N.9*	*na*	*na*			na		1,471,793	N.9
RATE OF RETURN ON AVERAGE RATE BASE	4.86%		8.81%							8.81%								8.81%	
REVENUE ADJUSTMENT (DIFFERENCE IN TOTAL OPERATING REVENUES)										$6,311								$6,293	

* Allocated Labor and Nonlabor of total O&M expenses based on 2009 Budget as provided in HECO-WP-101(A) in the 2009 Rate Case

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ATTACHMENT 10A
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N 1 See "Nominal" [illegible]n Worksheet
N 2 No escalator used.
N 9 Rate base in 2010 and 2011 grown by $30,638K (Estimate of coefficient for unit change in X variable (time)).
N.10 Based on 2009 TY RORB = 8.81%
N.11 (Total Operating Expenses less revenue taxes+Operating Income)/(1-PUC & PSC & Franchise Tax rates-Uncoll Factor) less Other Operating revenue & Gain on Sale of Land
N 12 Index based on growth rate of average rate base
N.13 Based on growth of O&M Expenses and Operating Income
N.14 See "Taxes" Tab in Worksheet
N.15 Based on growth rate submitted for 2009 Rate Case (Rate Case Update, HECO T-9, p.7)

Total Labor in Test Year

2009	81,136 4	
2010	81,136.4	100.00%
2011	81,136 4	100 00%

Total NonLabor in Test Year (excluding Fuel & Purchase Power expense)

2009	146,888 6	
2010	146,888 6	100.00%
2011	146,888 6	100 00%

Total O&M (excluding Fuel & Purchase Power expense)

2009	228,025.0	
2010	228,025 0	100.00%
2011	228,025 0	100.00%

Total Operating Income

2009	124,267.0	
2010	126,965 8	102.17%
2011	129,665.0	102.13%

Total O&M Expenses (excluding Fuel & Purchase Power expense) & Operating Income

2009	352,292.0	
2010	354,990 8	100.77%
2011	357,690.0	100.76%

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ATTACHMENT 10A

Hawaiian Electric Company, Inc.

CIP (Full Cost w/o Wind Studies & Sales Red) at Curr Eff Rates
COMPOSITE EMBEDDED COST OF CAPITAL
Estimated 2009 Average

	A	B	C	D
	Capitalization			
	Amount in Thousands	Percent of Total	Earnings Reqmts	Weighted Earnings Reqmts (B) x (C)
Short-Term Debt	21,951	1.49	3.25%	0.049%
Long-Term Debt	561,940	38.27	5.75%	2.200%
Hybrid Securities	27,775	1.89	7.41%	0.140%
Preferred Stock	59,496	4.05	7.62%	0.309%
Common Equity	797,308	54.30	11.25%	6.108%
Total	1,468,470	100.00		
Estimated Composite Cost of Capital				8.806%
			or	8.81%

Hawaiian Electric Company, Inc.

CIP (Full Cost w/o Wind Studies & Sales Red) at Curr Eff Rates
WORKING CASH ITEMS
2009
($ Thousands)

	A COLLECTION LAG (DAYS)	B PAYMENT LAG (DAYS)	C NET COLLECTION LAG (DAYS) (A - B)	D ANNUAL AMOUNT
ITEMS REQUIRING WORKING CASH				
Fuel Oil Purchases	37	17	20	809,058
O&M Labor	37	11	26	101,730
O&M Nonlabor	37	30	7	128,292
ITEMS THAT PROVIDE WORKING CASH				
Revenue Taxes	37	66	(29)	165,584
Income Taxes-Curr Eff Rates	37	39	(2)	14,307
Income Taxes-Proposed Rates	37	39	(2)	49,748
Purchased Power	37	37	0	477,055

	E AVERAGE DAILY AMOUNT (D/365)	F WORKING CASH (CURR EFF RATES) (C X E)	G AVERAGE DAILY AMOUNT (PROPOSED)	H WORKING CASH (PROPOSED RATES) (C X G)
ITEMS REQUIRING WORKING CASH				
Fuel Oil Purchases	2,217	44,332	2,217	44,332
O&M Labor	279	7,247	279	7,247
O&M Nonlabor	351	2,460	351	2,460
ITEMS THAT PROVIDE WORKING CASH				
Purchased Power	1,307	0	1,307	0
Revenue Taxes	454	(13,156)	478	(13,861)
Income Taxes-Curr Eff Rates	39	(78)		
Income Taxes-Proposed Rates	136	-	136	(273)
Total		40,805		39,905
Change in Working Cash				(900)

Hawaiian Electric Company, Inc.

CIP (Full Cost w/o Wind Studies & Sales Red) at Curr Eff Rates
COMPUTATION OF INCOME TAX EXPENSE
2009
($ Thousands)

	Current Effective Rates	Adjustment	At Proposed Rates
Operating Revenues	1,866,853	100,035	1,966,888
Operating Expenses:			
Fuel Oil and Purchased Power	1,293,709		1,293,709
Other Operation & Maintenance Expense	229,364	72	229,436
Depreciation	82,966		82,966
Amortization of State ITC	(1,453)		(1,453)
Taxes Other than Income	172,913	8,879	181,792
Interest on Customer Deposits	479		479
Total Operating Expenses	1,777,978	8,951	1,786,929
Operating Income Before Income Taxes	88,875	91,084	179,959
Tax Adjustments:			
Interest Expense	(33,697)		(33,697)
Meals and Entertainment	78		78
	(33,619)	0	(33,619)
Taxable Income at Ordinary Rates	55,256	91,084	146,340
Income Tax Exp at Ordinary Rates	21,500	35,441	56,941
Tax Benefit of Domestic Production Activities Deduction	1,226		1,226
Tax Effect of Deductible Preferred Stock Dividends	23		23
TOTAL INCOME TAX EXPENSE	20,251	35,441	55,692

Hawaiian Electric Company, Inc.

CIP (Full Cost w/o Wind Studies & Sales Red) at Curr Eff Rates
COMPUTATION OF TAXES OTHER THAN INCOME TAX
2009
($ Thousands)

	Rate	Current Effective Rates	Adjustment	At Proposed Rates
Electric Sales Revenue		1,861,751	99,913	1,961,664
Other Operating Revenue		4,487	122	4,609
Operating Revenues		1,866,238	100,035	1,966,273
Public Service Tax	5.885%	109,749	5,883	115,632
PUC Fees	0.500%	9,324	500	9,824
Franchise Tax	2.500%	46,510	2,496	49,006
Payroll Tax		7,330		7,330
TOTAL TAXES OTHER THAN INCOME TAX		172,913	8,879	181,792

Hawaiian Electric Company, Inc.

CIP (Full Cost w/o Wind Studies & Sales Red) at Curr Eff Rates
CALCULATIONS OF REVENUE REQUIREMENTS
2009
($ Thousands)

OPERATING INCOME AT CURRENT EFFECTIVE RATES:		
Operating Revenues		1,866,853
Fuel and Purchased Power Expenses		1,293,709
Other O&M Expenses		229,364
Depreciation & Amortization Expense		82,966
Amortization of State ITC		(1,453)
Taxes Other than Income		172,913
Interest on Customer Deposits		479
Income Taxes		20,251
Total Operating Expenses		1,798,229
OPERATING INCOME AT CURRENT EFFECTIVE RATES		68,624
CALCULATIONS OF REVENUE REQUIREMENTS:		
OPERATING INCOME		
Rate Base at Proposed Rates		1,410,517
Proposed Rate of Return on Rate Base	x	8.81%
Operating Income		124,267
Less: Operating Income at Current Effective Rate		68,624
INCREASE IN OPERATING INCOME		55,643
OPERATING REVENUES:		
Increase in Operating Income		55,643
Operating Income Divisor	(divided by)	0.55624
INCREASE IN OPERATING REVENUES		100,035
Increase in Electric Sales Revenue		99,913
Other Operating Revenue Rate	x	0.122%
Increase in Other Operating Revenues		122
		100,035

Hawaiian Electric Company, Inc.

CIP (Full Cost w/o Wind Studies & Sales Red) at Curr Eff Rates
CALCULATIONS OF REVENUE REQUIREMENTS
2009
($ Thousands)

BAD DEBT:		
Increase in Electric Revenues		99,913
Bad Debt Rate	x	0.0007
INCREASE IN BAD DEBT EXPENSE		72
REVENUE TAX:		
Increase in Operating Revenues		100,035
Less: Increase in Bad Debt Expense		(72)
		99,963
PSC Tax & PUC Fees Rate	x	6.385%
		6,383
Increase in Electric Revenues		99,913
Less: Increase in Bad Debt Expense		(72)
		99,841
Franchise Tax Rate	x	2.500%
		2,496
INCREASE IN REVENUE TAX		8,879
INCOME TAX:		
Increase in Operating Revenues		100,035
Effective Income Tax Rate after considering revenue tax & bad debt	x	35.428%
INCREASE IN INCOME TAX		35,441
INCREASE IN OPERATING INCOME (check)		55,643

Hawaiian Electric Company, Inc.

CIP (Full Cost w/o Wind Studies & Sales Red) at Curr Eff Rates
CALCULATIONS OF REVENUE REQUIREMENTS
2009
($ Thousands)

CHANGE IN RATE BASE:

	A EXPENSE AMOUNT	B AVERAGE DAILY AMOUNT (A/365)	C NET COLLECTION LAG (DAYS)	D WORKING CASH REQMT (B)x(C)
Increase in Revenue Tax	8,879	24	(29)	(705)
Income Tax at Curr Eff rate	14,307	39	(2)	78
Income Tax at proposed rate	49,748	136	(2)	(273)
CHANGE IN RATE BASE - WORKING CASH				(900)
Rate Base at Current Effective Rates				1,411,417
PROPOSED RATE BASE				1,410,517
Operating Income at Current Effective Rates				68,624
Increase in Operating Income				55,643
OPERATING INCOME AT PROPOSED RATES				124,267
PROPOSED RATE OF RETURN ON RATE BASE (check)				8.81%

Decoupling - Proposal
Results of Operations
Based on 2009 Test Year
($ Thousands)

	Revenue Requirements to Produce 8.81% Return on Average Rate Base	Nominal Amount in TY 2009	2010 Nominal Amount	2011 Nominal Amount	2012 Nominal Amount	Comments
Electric Sales Revenue	1,961,664					
Other Operating Revenue	4,609	4,609	4,609	4,609	4,609	Updated HECO-304 (Update, T-3, Att. 4, p. 1
Gain on Sale of Land	615	615	615	615	615	
TOTAL OPERATING REVENUES	1,966,888	5,224	5,224	5,224	5,224	
Fuel	816,654	816,654	816,654	816,654		ECAC Recovery - amount in base rates
Purchased Power	477,055	477,055	477,055	477,055		ECAC Recovery - amount in base rates
Production	82,423					
Transmission	13,930					
Distribution	30,515					
Customer Accounts	16,297					
Allowance for Uncoll. Accounts	1,411					
Customer Service	6,997					
Administration & General	77,863					
	na					
	na					
	na					
	na	14,076	14,076	14,076		Nominal Tab, Attachment 1
	na	5,022	5,022	5,022		Nominal Tab, Attachment 1
A&G Total Nominal Amounts		19,098	19,098	19,098		
Operation and Maintenance/Total Nominal Amounts	1,523,145	1,312,807	1,312,807	1,312,807		

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Hawaiian Electric Company, Inc.

CIP (Full Cost w/o Wind Studies & Sales Red) at Curr Eff Rates
SUPPORT WORKSHEET

		2009	2010	2011
REVENUE TAX				
Public Service Tax				
Electric Sales Revenues		1,861,751	1,967,974.9	1,974,267.7
Other Operating Revenues		4,487	4,609.0	4,609.0
Less: Bad Debt Expense		(1,339)	(1,421.8)	(1,432.6)
Operating Revenues subject to PSC Tax		1,864,899	1,971,162	1,977,444
Public Service Tax Rate	x	5.885%	5.885%	5.885%
Total PSC Tax		109,749	116,003	116,373
PUC Fees				
Electric Sales Revenues		1,861,751	1,967,974.9	1,974,267.7
Other Operating Revenues		4,487	4,609.0	4,609.0
Less: Bad Debt Expense		(1,339)	(1,421.8)	(1,432.6)
Operating Revenues subject to PSC Tax		1,864,899	1,971,162	1,977,444
PUC Tax Rate	x	0.500%	0.500%	0.500%
Total PUC Tax		9,324	9,856	9,887
Franchise Tax				
Electric Sales Revenues		1,861,751	1,967,974.9	1,974,267:7
Less: Bad Debt Expense		(1,339)	(1,421.8)	(1,432.6)
		1,860,412	1,966,553	1,972,835
Franchise Tax Rate	x	2.500%	2.500%	2.500%
Total Franchise Tax		46,510	49,164	49,321
TOTAL REVENUE TAX		165,584	175,023	175,581

Maui Electric Company, Limited (MECO)

Rate Base Forecast Only
Rate Case -2007 Test Year - Probable Entitlement
Estimated 2006 Rate Case Average

Capitalization

	A	B	C	D
	Amount in Thousands	Percent of Total	Earnings Reqmts	Weighted Earnings Reqmts (B) x (C)
Short-Term Debt	4,750	1.27	5.00%	0.063%
Revenue Bond	150,585	40.15	6.11%	2.453%
Hybrid Securities	9,192	2.45	7.47%	0.183%
Preferred Stock	4,693	1.25	8.34%	0.104%
Common Equity	205,882	54.89	10.70%	5.873%
Total	375,102	100.00		
Estimated Composite Cost of Capital				8.676%
			or	8.68%

Hawaii Electric Light Company, Inc. (HELCO)

Rate Base Forecast Based on Regression Estimate Only
Rate Case -2006 Test Year - Settlement Results of Operatic
Estimated 2006 Rate Case Average

	A	B	C	D
	Capitalization			
	Amount in Thousands	Percent of Total	Earnings Reqmts	Weighted Earnings Reqmts (B) x (C)
Short-Term Debt	49,550	13.24	5.00%	0.662%
Revenue Bond	117,408	31.37	5.92%	1.857%
Hybrid Securities	9,152	2.45	7.50%	0.183%
Preferred Stock	6,563	1.75	8.37%	0.147%
Common Equity	191,544	51.19	10.70%	5.477%
Total	374,217	100.00		
Estimated Composite Cost of Capital				8.326%
			or	8.33%

Hawaiian Elec[illegible]ompany, Inc
Decoupling - Proposal (Significant Project Methodology - AVERAGE RATE BASE)
Results of Operations
Based on 2009 Test Year
($ Thousands)

	Current Effective Rates	Additional Amount	Revenue Requirements to Produce 8 81% Return on Average Rate Base	2009 Nominal Amount (N 1)	2009 BAU Amount	2009 1 + Index	Notes	2010 BAU * Index Amount	2010 Nominal Amount (N.1)	2010 TOTAL RAM Amount	Notes	2010 Nominal Amount	2011 BAU Amount	2011 1 + Index	Notes	2011 BAU * Index Amount	2011 Nominal Amount	2011 TOTAL RAM Amount	Notes
Electric Sales Revenue	1,861,751	99,913	1,961,664					0		1,969,975	N.11							1,974,106	N 11
Other Operating Revenue	4,487	122	4,609	4,609	0			0	4,609	4,609		4,609					4,609	4,609	
Gain on Sale of Land	615		615	615	0	100.0%	N 2	0	615	615		615	0	100.0%	N.2	0	615	615	
TOTAL OPERATING REVENUES	1,866,853	100,035	1,966,888	5,224	0			0		1,975,199		5,224	0			0		1,979,330	
Fuel	816,654		816,654	816,654	0	100.0%	N.2	0	816,654	816,654		816,654	0	100.0%	N.2	0	816,654	816,654	
Purchased Power	477,055		477,055	477,055	0	100.0%	N 2	0	477,055	477,055		477,055	0	100 0%	N.2	0	477,055	477,055	
Production	82,423		82,423																
Production Labor *			33,819		33,819	100.0%	N 2	33,819		33,819		0	33,819	100 0%	N.2	33,819		33,819	
Production NonLabor *			48,604	0	48,604	100.0%	N.2	48,604	0	48,604		0	48,604	100 0%	N.2	48,604	0	48,604	
Transmission	13,930		13,930																
Transmission Labor *			4,951		4,951	100.0%	N 2	4,951		4,951		0	4,951	100.0%	N.2	4,951		4,951	
Transmission NonLabor *			8,979		8,979	100.0%	N.2	8,979		8,979		0	8,979	100.0%	N.2	8,979		8,979	
Distribution	30,515		30,515																
Distribution Labor *			12,474		12,474	100 0%	N 2	12,474		12,474		0	12,474	100 0%	N.2	12,474		12,474	
Distribution NonLabor *			18,041	0	18,041	100 0%	N 2	18,041	0	18,041		0	18,041	100.0%	N 2	18,041	0	18,041	
Customer Accounts	16,297		16,297																
Customer Accounts Labor *			7,729		7,729	100.0%	N.2	7,729		7,729		0	7,729	100.0%	N.2	7,729		7,729	
Customer Accounts NonLabor *			8,568	0	8,568	100 0%	N 2	8,568	0	8,568		0	8,568	100 0%	N 2	8,568	0	8,568	
Allowance for Uncoll. Accounts	1,339	72	1,411		1,411	100 6%	N 13	1,420		1,420		0	1,420	100 5%	N.13	1,427		1,427	
Customer Service	6,997		6,997																
Customer Service Labor *			964		964	100 0%	N 2	964		964		0	964	100.0%	N.2	964		964	
Customer Service NonLabor *			6,033		6,033	100.0%	N.2	6,033		6,033		0	6,033	100.0%	N.2	6,033		6,033	
Administration & General	77,863		77,863							0		0						0	
Admin & Gen Labor *			21,199		21,199	100 0%	N 2	21,199		21,199		0	21,199	100.0%	N.2	21,199		21,199	
Admin & Gen NonLabor *			56,664	19,098	37,566	100.0%	N 2	37,566	19,098	56,664		19,098	37,566	100.0%	N 2	37,566	19,098	56,664	
Operation and Maintenance	1,523,073	72	1,523,145	1,312,807	210,338			210,347		1,523,154		1,312,807	210,347			210,354	1,312,807	1,523,161	
Depreciation & Amortization	82,966		82,966	na	na			na		87,207	N.12	na	na			na		88,411	N.12
Amortization of State ITC	(1,453)		(1,453)		-1,453	101.8%	N 12	-1,480		-1,480		0	-1,480	101 4%	N.12	-1,500		-1,500	N.12
Taxes Other Than Income	172,913	8,879	181,792	na	na			na		182,530	N 14	na	na			na		182,897	N 14
Interest on Customer Deposits	479		479		479	108.5%	N.15	520		520		0	520	108.5%	N.15	564		564	
Income Taxes	*20,251*	35,441	55,692	*na*	na			*na*		56,710		na	na			na		57,493	
TOTAL OPERATING EXPENSES	1,798,229	44,392	1,842,621	1,312,807	209,364			209,387		1,848,642		1,312,807	209,387			209,418		1,851,026	
													0			0		0	
OPERATING INCOME	68,624	55,643	124,267	na	na			na		126,538	N.10	na	na			0		128,285	N 10
								0		0			0			0		0	
AVERAGE RATE BASE	1,411,417	(900)	1,410,517	na	na			na		1,436,299	N 9	na	na			na		1,456,127	N.9
RATE OF RETURN ON AVERAGE RATE BASE	4.86%		8 81%							8.81%								8.81%	
REVENUE ADJUSTMENT (DIFFERENCE IN TOTAL OPERATING REVENUES)										$8,311								$4,131	

* Allocated Labor and Nonlabor of total O&M expenses based on 2009 Budget as provided in HECO-WP-101(A) in the 2009 Rate Case

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N.1 See "Nomina[illegible] in Worksheet
N 2 No escalator used
N 9 Rate base in 2010 and 2011 grown by $15,177K (Estimate of coefficient for unit change in X variable (time)), based on average rate base less significant projects
N.10 Based on 2009 TY RORB = 8 81%
N.11 (Total Operating Expenses less revenue taxes+Operating Income)/(1-PUC & PSC & Franchise Tax rates-Uncoll Factor) less Other Operating revenue & Gain on Sale of Land
N 12 Index based on growth rate of average rate base In 2010, CIP CT-1 depreciation added In 2011, index based on growth rate of average rate base.
N 13 Based on growth of O&M Expenses and Operating Income
N 14 See "Taxes" Tab in Worksheet
N.15 Based on growth rate submitted for 2009 Rate Case (Rate Case Update, HECO T-9, p 7)

Total Labor in Test Year

2009	81,136 4	
2010	81,136.4	100.00%
2011	81,136.4	100.00%

Total NonLabor in Test Year (excluding Fuel & Purchase Power expense)

2009	#########	
2010	#########	100 00%
2011	#########	100.00%

Total O&M (excluding Fuel & Purchase Power expense)

2009	#########	
2010	#########	100.00%
2011	#########	100 00%

Total Operating Income

2009	#########	
2010	#########	101 83%
2011	#########	101.38%

Total O&M Expenses (excluding Fuel & Purchase Power expense) & Operating Income

2009	#########	
2010	#########	100.64%
2011	#########	100.49%

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Hawaiian Electric Company, Inc.

CIP (Full Cost w/o Wind Studies & Sales Red) at Curr Eff Rates
COMPOSITE EMBEDDED COST OF CAPITAL
Estimated 2009 Average

	A	B	C	D
	Capitalization			
	Amount in Thousands	Percent of Total	Earnings Reqmts	Weighted Earnings Reqmts (B) x (C)
Short-Term Debt	21,951	1.49	3.25%	0.049%
Long-Term Debt	561,940	38.27	5.75%	2.200%
Hybrid Securities	27,775	1.89	7.41%	0.140%
Preferred Stock	59,496	4.05	7.62%	0.309%
Common Equity	797,308	54.30	11.25%	6.108%
Total	1,468,470	100.00		

Estimated Composite Cost of Capital	8.806%
or	8.81%

Hawaiian Electric Company, Inc.

CIP (Full Cost w/o Wind Studies & Sales Red) at Curr Eff Rates
WORKING CASH ITEMS
2009
($ Thousands)

	A COLLECTION LAG (DAYS)	B PAYMENT LAG (DAYS)	C NET COLLECTION LAG (DAYS) (A - B)	D ANNUAL AMOUNT
ITEMS REQUIRING WORKING CASH				
Fuel Oil Purchases	37	17	20	809,058
O&M Labor	37	11	26	101,730
O&M Nonlabor	37	30	7	128,292
ITEMS THAT PROVIDE WORKING CASH				
Revenue Taxes	37	66	(29)	165,584
Income Taxes-Curr Eff Rates	37	39	(2)	14,307
Income Taxes-Proposed Rates	37	39	(2)	49,748
Purchased Power	37	37	0	477,055

	E AVERAGE DAILY AMOUNT (D/365)	F WORKING CASH (CURR EFF RATES) (C X E)	G AVERAGE DAILY AMOUNT (PROPOSED)	H WORKING CASH (PROPOSED RATES) (C X G)
ITEMS REQUIRING WORKING CASH				
Fuel Oil Purchases	2,217	44,332	2,217	44,332
O&M Labor	279	7,247	279	7,247
O&M Nonlabor	351	2,460	351	2,460
ITEMS THAT PROVIDE WORKING CASH				
Purchased Power	1,307	0	1,307	0
Revenue Taxes	454	(13,156)	478	(13,861)
Income Taxes-Curr Eff Rates	39	(78)		
Income Taxes-Proposed Rates	136	-	136	(273)
Total		40,805		39,905
Change in Working Cash				(900)

Hawaiian Electric Company, Inc.

CIP (Full Cost w/o Wind Studies & Sales Red) at Curr Eff Rates
COMPUTATION OF INCOME TAX EXPENSE
2009
($ Thousands)

	Current Effective Rates	Adjustment	At Proposed Rates
Operating Revenues	1,866,853	100,035	1,966,888
Operating Expenses:			
Fuel Oil and Purchased Power	1,293,709		1,293,709
Other Operation & Maintenance Expense	229,364	72	229,436
Depreciation	82,966		82,966
Amortization of State ITC	(1,453)		(1,453)
Taxes Other than Income	172,913	8,879	181,792
Interest on Customer Deposits	479		479
Total Operating Expenses	1,777,978	8,951	1,786,929
Operating Income Before Income Taxes	88,875	91,084	179,959
Tax Adjustments:			
Interest Expense	(33,697)		(33,697)
Meals and Entertainment	78		78
	(33,619)	0	(33,619)
Taxable Income at Ordinary Rates	55,256	91,084	146,340
Income Tax Exp at Ordinary Rates	21,500	35,441	56,941
Tax Benefit of Domestic Production Activities Deduction	1,226		1,226
Tax Effect of Deductible Preferred Stock Dividends	23		23
TOTAL INCOME TAX EXPENSE	20,251	35,441	55,692

Hawaiian Electric Company, Inc.

CIP (Full Cost w/o Wind Studies & Sales Red) at Curr Eff Rates
COMPUTATION OF TAXES OTHER THAN INCOME TAX
2009
($ Thousands)

	Rate	Current Effective Rates	Adjustment	At Proposed Rates
Electric Sales Revenue		1,861,751	99,913	1,961,664
Other Operating Revenue		4,487	122	4,609
Operating Revenues		1,866,238	100,035	1,966,273
Public Service Tax	5.885%	109,749	5,883	115,632
PUC Fees	0.500%	9,324	500	9,824
Franchise Tax	2.500%	46,510	2,496	49,006
Payroll Tax		7,330		7,330
TOTAL TAXES OTHER THAN INCOME TAX		172,913	8,879	181,792

Hawaiian Electric Company, Inc.

CIP (Full Cost w/o Wind Studies & Sales Red) at Curr Eff Rates
CALCULATIONS OF REVENUE REQUIREMENTS
2009
($ Thousands)

OPERATING INCOME AT CURRENT EFFECTIVE RATES:		
Operating Revenues		1,866,853
Fuel and Purchased Power Expenses		1,293,709
Other O&M Expenses		229,364
Depreciation & Amortization Expense		82,966
Amortization of State ITC		(1,453)
Taxes Other than Income		172,913
Interest on Customer Deposits		479
Income Taxes		20,251
Total Operating Expenses		1,798,229
OPERATING INCOME AT CURRENT EFFECTIVE RATES		68,624
CALCULATIONS OF REVENUE REQUIREMENTS:		
OPERATING INCOME		
Rate Base at Proposed Rates		1,410,517
Proposed Rate of Return on Rate Base	x	8.81%
Operating Income		124,267
Less: Operating Income at Current Effective Rate		68,624
INCREASE IN OPERATING INCOME		55,643
OPERATING REVENUES:		
Increase in Operating Income		55,643
Operating Income Divisor	(divided by)	0.55624
INCREASE IN OPERATING REVENUES		100,035
Increase in Electric Sales Revenue		99,913
Other Operating Revenue Rate	x	0.122%
Increase in Other Operating Revenues		122
		100,035

Hawaiian Electric Company, Inc.

CIP (Full Cost w/o Wind Studies & Sales Red) at Curr Eff Rates
CALCULATIONS OF REVENUE REQUIREMENTS
2009
($ Thousands)

BAD DEBT:		
Increase in Electric Revenues		99,913
Bad Debt Rate	x	0.0007
INCREASE IN BAD DEBT EXPENSE		72
REVENUE TAX:		
Increase in Operating Revenues		100,035
Less: Increase in Bad Debt Expense		(72)
		99,963
PSC Tax & PUC Fees Rate	x	6.385%
		6,383
Increase in Electric Revenues		99,913
Less: Increase in Bad Debt Expense		(72)
		99,841
Franchise Tax Rate	x	2.500%
		2,496
INCREASE IN REVENUE TAX		8,879
INCOME TAX:		
Increase in Operating Revenues		100,035
Effective Income Tax Rate after considering revenue tax & bad debt	x	35.428%
INCREASE IN INCOME TAX		35,441
INCREASE IN OPERATING INCOME (check)		55,643

Hawaiian Electric Company, Inc.

CIP (Full Cost w/o Wind Studies & Sales Red) at Curr Eff Rates
CALCULATIONS OF REVENUE REQUIREMENTS
2009
($ Thousands)

CHANGE IN RATE BASE:

	A EXPENSE AMOUNT	B AVERAGE DAILY AMOUNT (A/365)	C NET COLLECTION LAG (DAYS)	D WORKING CASH REQMT (B)x(C)
Increase in Revenue Tax	8,879	24	(29)	(705)
Income Tax at Curr Eff rate	14,307	39	(2)	78
Income Tax at proposed rate	49,748	136	(2)	(273)
CHANGE IN RATE BASE - WORKING CASH				(900)
Rate Base at Current Effective Rates				1,411,417
PROPOSED RATE BASE				1,410,517
Operating Income at Current Effective Rates				68,624
Increase in Operating Income				55,643
OPERATING INCOME AT PROPOSED RATES				124,267
PROPOSED RATE OF RETURN ON RATE BASE (check)				8.81%

Decoupling - Proposal
Results of Operations
Based on 2009 Test Year
($ Thousands)

	Revenue Requirements to Produce 8.81% Return on Average Rate Base	Nominal Amount in TY 2009	2010 Nominal Amount	2011 Nominal Amount	2012 Nominal Amount	Comments
Electric Sales Revenue	1,961,664					
Other Operating Revenue	4,609	4,609	4,609	4,609	4,609	Updated HECO-304 (Update, T-3, Att. 4, p. 1
Gain on Sale of Land	615	615	615	615	615	
TOTAL OPERATING REVENUES	1,966,888	5,224	5,224	5,224	5,224	
Fuel	816,654	816,654	816,654	816,654		ECAC Recovery - amount in base rates
Purchased Power	477,055	477,055	477,055	477,055		ECAC Recovery - amount in base rates
Production	82,423					
Transmission	13,930					
Distribution	30,515					
Customer Accounts	16,297					
Allowance for Uncoll. Accounts	1,411					
Customer Service	6,997					
Administration & General	77,863					
	na					
	na					
	na					
	na	14,076	14,076	14,076		Nominal Tab, Attachment 1
	na	5,022	5,022	5,022		Nominal Tab, Attachment 1
A&G Total Nominal Amounts		19,098	19,098	19,098		
Operation and Maintenance/Total Nominal Amounts	1,523,145	1,312,807	1,312,807	1,312,807		

Hawaiian Electric Company, Inc.

CIP (Full Cost w/o Wind Studies & Sales Red) at Curr Eff Rates
SUPPORT WORKSHEET

		2009	2010	2011
REVENUE TAX				
Public Service Tax				
Electric Sales Revenues		1,861,751	1,969,975.5	1,974,106.4
Other Operating Revenues		4,487	4,609.0	4,609.0
Less: Bad Debt Expense		(1,339)	(1,420.1)	(1,427.1)
Operating Revenues subject to PSC Tax		1,864,899	1,973,164	1,977,288
Public Service Tax Rate	x	5.885%	5.885%	5.885%
Total PSC Tax		109,749	116,121	116,363
PUC Fees				
Electric Sales Revenues		1,861,751	1,969,975.5	1,974,106.4
Other Operating Revenues		4,487	4,609.0	4,609.0
Less: Bad Debt Expense		(1,339)	(1,420.1)	(1,427.1)
Operating Revenues subject to PSC Tax		1,864,899	1,973,164	1,977,288
PUC Tax Rate	x	0.500%	0.500%	0.500%
Total PUC Tax		9,324	9,866	9,886
Franchise Tax				
Electric Sales Revenues		1,861,751	1,969,975.5	1,974,106.4
Less: Bad Debt Expense		(1,339)	(1,420.1)	(1,427.1)
		1,860,412	1,968,555	1,972,679
Franchise Tax Rate	x	2.500%	2.500%	2.500%
Total Franchise Tax		46,510	49,214	49,317
TOTAL REVENUE TAX		165,584	175,200	175,567

Hawaiian Ele[illegible]ompany, Inc
Decoupling - Proposal (Significant Project Methodology - Full Cost of Project in RATE BASE)
Results of Operations
Based on 2009 Test Year
($ Thousands)

	Current Effective Rates	Additional Amount	Revenue Requirements to Produce 8.81% Return on Average Rate Base	2009 Nominal Amount (N 1)	2009 BAU Amount	2009 1 + Index	Notes	2010 BAU * Index Amount	2010 Nominal Amount (N.1)	2010 TOTAL RAM Amount	Notes	2010 Nominal Amount	2011 BAU Amount	2011 1 + Index	Notes	2011 BAU * Index Amount	2011 Nominal Amount	2011 TOTAL RAM Amount	Notes
Electric Sales Revenue	1,861,751	99,913	1,961,664					0		1,971,687	N 11							1,974,089	N 11
Other Operating Revenue	4,487	122	4,609	4,609	0			0	4,609	4,609		4,609					4,609	4,609	
Gain on Sale of Land	615		615	615	0	100 0%	N 2	0	615	615		615	0	100 0%	N 2	0	615	615	
TOTAL OPERATING REVENUES	1,866,853	100,035	1,966,888	5,224	0			0		1,976,911		5,224	0			0		1,979,313	
Fuel	816,654		816,654	816,654	0	100 0%	N 2	0	816,654	816,654		816,654	0	100 0%	N 2	0	816,654	816,654	
Purchased Power	477,055		477,055	477,055	0	100.0%	N 2	0	477,055	477,055		477,055	0	100.0%	N.2	0	477,055	477,055	
Production	82,423		82,423																
Production Labor *			33,819		33,819	100.0%	N.2	33,819		33,819		0	33,819	100 0%	N 2	33,819		33,819	
Production NonLabor *			48,604	0	48,604	100 0%	N 2	48,604	0	48,604		0	48,604	100 0%	N 2	48,604	0	48,604	
Transmission	13,930		13,930																
Transmission Labor *			4,951		4,951	100.0%	N.2	4,951		4,951		0	4,951	100 0%	N 2	4,951		4,951	
Transmission NonLabor *			8,979		8,979	100 0%	N 2	8,979		8,979		0	8,979	100 0%	N 2	8,979		8,979	
Distribution	30,515		30,515																
Distribution Labor *			12,474		12,474	100.0%	N 2	12,474		12,474		0	12,474	100.0%	N.2	12,474		12,474	
Distribution NonLabor *			18,041	0	18,041	100.0%	N.2	18,041	0	18,041		0	18,041	100 0%	N.2	18,041	0	18,041	
Customer Accounts	16,297		16,297																
Customer Accounts Labor *			7,729		7,729	100.0%	N 2	7,729		7,729		0	7,729	100 0%	N 2	7,729		7,729	
Customer Accounts NonLabor *			8,568	0	8,568	100.0%	N 2	8,568	0	8,568		0	8,568	100.0%	N.2	8,568	0	8,568	
Allowance for Uncoll Accounts	1,339	72	1,411		1,411	100.9%	N 13	1,423		1,423		0	1,423	100.3%	N.13	1,427		1,427	
Customer Service	6,997		6,997																
Customer Service Labor *			964		964	100.0%	N 2	964		964		0	964	100 0%	N 2	964		964	
Customer Service NonLabor *			6,033		6,033	100.0%	N 2	6,033		6,033		0	6,033	100.0%	N.2	6,033		6,033	
Administration & General	77,863		77,863							0		0						0	
Admin & Gen Labor *			21,199		21,199	100.0%	N 2	21,199		21,199		0	21,199	100 0%	N.2	21,199		21,199	
Admin & Gen NonLabor *			56,664	19,098	37,566	100 0%	N 2	37,566	19,098	56,664		19,098	37,566	100 0%	N 2	37,566	19,098	56,664	
Operation and Maintenance	1,523,073	72	1,523,145	1,312,807	210,338			210,350		1,523,157		1,312,807	210,350			210,354	1,312,807	1,523,161	
Depreciation & Amortization	82,966		82,966	na	na			na		87,702	N.12	na	na			na		88,395	N.12
Amortization of State ITC	(1,453)		(1,453)		-1,453	102.4%	N 12	-1,488		-1,488		0	-1,488	100.8%	N.12	-1,500		-1,500	N.12
Taxes Other Than Income	172,913	8,879	181,792	na	na			na		182,682	N 14	na	na			na		182,895	N.14
Interest on Customer Deposits	479		479		479	108 5%	N.15	520		520		0	520	108.5%	N 15	564		564	
Income Taxes	20,251	35,441	55,692	na	na			na		57,041		na	na			na		57,493	
TOTAL OPERATING EXPENSES	1,798,229	44,392	1,842,621	1,312,807	209,364			209,382		1,849,614		1,312,807	209,382			209,418		1,851,008	
													0			0		0	
OPERATING INCOME	68,624	55,643	124,267	na	na			na		127,278	N 10	na	na			0		128,285	N.10
								0		0			0			0		0	
AVERAGE RATE BASE	1,411,417	(900)	1,410,517	na	na			na		1,444,698	N 9	na	na			na		1,456,127	N.9
RATE OF RETURN ON AVERAGE RATE BASE	4 86%		8 81%							8.81%								8.81%	
REVENUE ADJUSTMENT (DIFFERENCE IN TOTAL OPERATING REVENUES)										$10,023								$2,402	

* Allocated Labor and Nonlabor of total O&M expenses based on 2009 Budget as provided in HECO-WP-101(A) in the 2009 Rate Case

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N 1 See "Nominal" [illegible] in Worksheet
N.2 No escalator used.
N 9 Rate base in 2010 and 2011 grown by $15.177K (Estimate of coefficient for unit change in X variable (time)), based on average rate base less significant projects
N 10 Based on 2009 TY RORB = 8 81%
N 11 (Total Operating Expenses less revenue taxes+Operating Income)/(1-PUC & PSC & Franchise Tax rates-Uncoll Factor) less Other Operating revenue & Gain on Sale of Land
N 12 Index based on growth rate of average rate base. In 2010, CIP CT-1 depreciation added In 2011, index based on growth rate of average rate base.
N.13 Based on growth of O&M Expenses and Operating Income
N 14 See "Taxes" Tab in Worksheet
N 15 Based on growth rate submitted for 2009 Rate Case (Rate Case Update, HECO T-9, p 7)

Total Labor in Test Year

2009	81,136 4	
2010	81,136 4	100.00%
2011	81,136.4	100 00%

Total NonLabor in Test Year (excluding Fuel & Purchase Power expense)

2009	#########	
2010	#########	100 00%
2011	#########	100.00%

Total O&M (excluding Fuel & Purchase Power expense)

2009	#########	
2010	#########	100.00%
2011	#########	100.00%

Total Operating Income

2009	#########	
2010	#########	102.42%
2011	#########	100 79%

Total O&M Expenses (excluding Fuel & Purchase Power expense) & Operating Income

2009	#########	
2010	#########	100.85%
2011	#########	100.28%

Hawaiian Electric Company, Inc.

CIP (Full Cost w/o Wind Studies & Sales Red) at Curr Eff Rates
COMPOSITE EMBEDDED COST OF CAPITAL
Estimated 2009 Average

	A	B	C	D
	Capitalization			
	Amount in Thousands	Percent of Total	Earnings Reqmts	Weighted Earnings Reqmts (B) x (C)
Short-Term Debt	21,951	1.49	3.25%	0.049%
Long-Term Debt	561,940	38.27	5.75%	2.200%
Hybrid Securities	27,775	1.89	7.41%	0.140%
Preferred Stock	59,496	4.05	7.62%	0.309%
Common Equity	797,308	54.30	11.25%	6.108%
Total	1,468,470	100.00		
Estimated Composite Cost of Capital				8.806%
			or	8.81%

Hawaiian Electric Company, Inc.

CIP (Full Cost w/o Wind Studies & Sales Red) at Curr Eff Rates
WORKING CASH ITEMS
2009
($ Thousands)

	A COLLECTION LAG (DAYS)	B PAYMENT LAG (DAYS)	C NET COLLECTION LAG (DAYS) (A - B)	D ANNUAL AMOUNT
ITEMS REQUIRING WORKING CASH				
Fuel Oil Purchases	37	17	20	809,058
O&M Labor	37	11	26	101,730
O&M Nonlabor	37	30	7	128,292
ITEMS THAT PROVIDE WORKING CASH				
Revenue Taxes	37	66	(29)	165,584
Income Taxes-Curr Eff Rates	37	39	(2)	14,307
Income Taxes-Proposed Rates	37	39	(2)	49,748
Purchased Power	37	37	0	477,055

	E AVERAGE DAILY AMOUNT (D/365)	F WORKING CASH (CURR EFF RATES) (C X E)	G AVERAGE DAILY AMOUNT (PROPOSED)	H WORKING CASH (PROPOSED RATES) (C X G)
ITEMS REQUIRING WORKING CASH				
Fuel Oil Purchases	2,217	44,332	2,217	44,332
O&M Labor	279	7,247	279	7,247
O&M Nonlabor	351	2,460	351	2,460
ITEMS THAT PROVIDE WORKING CASH				
Purchased Power	1,307	0	1,307	0
Revenue Taxes	454	(13,156)	478	(13,861)
Income Taxes-Curr Eff Rates	39	(78)		
Income Taxes-Proposed Rates	136	-	136	(273)
Total		40,805		39,905
Change in Working Cash				(900)

Hawaiian Electric Company, Inc.

CIP (Full Cost w/o Wind Studies & Sales Red) at Curr Eff Rates
COMPUTATION OF INCOME TAX EXPENSE
2009
($ Thousands)

	Current Effective Rates	Adjustment	At Proposed Rates
Operating Revenues	1,866,853	100,035	1,966,888
Operating Expenses:			
Fuel Oil and Purchased Power	1,293,709		1,293,709
Other Operation & Maintenance Expense	229,364	72	229,436
Depreciation	82,966		82,966
Amortization of State ITC	(1,453)		(1,453)
Taxes Other than Income	172,913	8,879	181,792
Interest on Customer Deposits	479		479
Total Operating Expenses	1,777,978	8,951	1,786,929
Operating Income Before Income Taxes	88,875	91,084	179,959
Tax Adjustments:			
Interest Expense	(33,697)		(33,697)
Meals and Entertainment	78		78
	(33,619)	0	(33,619)
Taxable Income at Ordinary Rates	55,256	91,084	146,340
Income Tax Exp at Ordinary Rates	21,500	35,441	56,941
Tax Benefit of Domestic Production Activities Deduction	1,226		1,226
Tax Effect of Deductible Preferred Stock Dividends	23		23
TOTAL INCOME TAX EXPENSE	20,251	35,441	55,692

Hawaiian Electric Company, Inc.

CIP (Full Cost w/o Wind Studies & Sales Red) at Curr Eff Rates
COMPUTATION OF TAXES OTHER THAN INCOME TAX
2009
($ Thousands)

	Rate	Current Effective Rates	Adjustment	At Proposed Rates
Electric Sales Revenue		1,861,751	99,913	1,961,664
Other Operating Revenue		4,487	122	4,609
Operating Revenues		1,866,238	100,035	1,966,273
Public Service Tax	5.885%	109,749	5,883	115,632
PUC Fees	0.500%	9,324	500	9,824
Franchise Tax	2.500%	46,510	2,496	49,006
Payroll Tax		7,330		7,330
TOTAL TAXES OTHER THAN INCOME TAX		172,913	8,879	181,792

Hawaiian Electric Company, Inc.

CIP (Full Cost w/o Wind Studies & Sales Red) at Curr Eff Rates
CALCULATIONS OF REVENUE REQUIREMENTS
2009
($ Thousands)

OPERATING INCOME AT CURRENT EFFECTIVE RATES:		
Operating Revenues		1,866,853
Fuel and Purchased Power Expenses		1,293,709
Other O&M Expenses		229,364
Depreciation & Amortization Expense		82,966
Amortization of State ITC		(1,453)
Taxes Other than Income		172,913
Interest on Customer Deposits		479
Income Taxes		20,251
Total Operating Expenses		1,798,229
OPERATING INCOME AT CURRENT EFFECTIVE RATES		68,624
CALCULATIONS OF REVENUE REQUIREMENTS:		
OPERATING INCOME		
Rate Base at Proposed Rates		1,410,517
Proposed Rate of Return on Rate Base	x	8.81%
Operating Income		124,267
Less: Operating Income at Current Effective Rate		68,624
INCREASE IN OPERATING INCOME		55,643
OPERATING REVENUES:		
Increase in Operating Income		55,643
Operating Income Divisor	(divided by)	0.55624
INCREASE IN OPERATING REVENUES		100,035
Increase in Electric Sales Revenue		99,913
Other Operating Revenue Rate	x	0.122%
Increase in Other Operating Revenues		122
		100,035

Hawaiian Electric Company, Inc.

CIP (Full Cost w/o Wind Studies & Sales Red) at Curr Eff Rates
CALCULATIONS OF REVENUE REQUIREMENTS
2009
($ Thousands)

BAD DEBT:		
Increase in Electric Revenues		99,913
Bad Debt Rate	x	0.0007
INCREASE IN BAD DEBT EXPENSE		72
REVENUE TAX:		
Increase in Operating Revenues		100,035
Less: Increase in Bad Debt Expense		(72)
		99,963
PSC Tax & PUC Fees Rate	x	6.385%
		6,383
Increase in Electric Revenues		99,913
Less: Increase in Bad Debt Expense		(72)
		99,841
Franchise Tax Rate	x	2.500%
		2,496
INCREASE IN REVENUE TAX		8,879
INCOME TAX:		
Increase in Operating Revenues		100,035
Effective Income Tax Rate after considering revenue tax & bad debt	x	35.428%
INCREASE IN INCOME TAX		35,441
INCREASE IN OPERATING INCOME (check)		55,643

Hawaiian Electric Company, Inc.

CIP (Full Cost w/o Wind Studies & Sales Red) at Curr Eff Rates
CALCULATIONS OF REVENUE REQUIREMENTS
2009
($ Thousands)

CHANGE IN RATE BASE:

	A EXPENSE AMOUNT	B AVERAGE DAILY AMOUNT (A/365)	C NET COLLECTION LAG (DAYS)	D WORKING CASH REQMT (B)x(C)
Increase in Revenue Tax	8,879	24	(29)	(705)
Income Tax at Curr Eff rate	14,307	39	(2)	78
Income Tax at proposed rate	49,748	136	(2)	(273)
CHANGE IN RATE BASE - WORKING CASH				(900)
Rate Base at Current Effective Rates				1,411,417
PROPOSED RATE BASE				1,410,517
Operating Income at Current Effective Rates				68,624
Increase in Operating Income				55,643
OPERATING INCOME AT PROPOSED RATES				124,267
PROPOSED RATE OF RETURN ON RATE BASE (check)				8.81%

Decoupling - Proposal
Results of Operations
Based on 2009 Test Year
($ Thousands)

	Revenue Requirements to Produce 8.81% Return on Average Rate Base	Nominal Amount in TY 2009	2010 Nominal Amount	2011 Nominal Amount	2012 Nominal Amount	Comments
Electric Sales Revenue	1,961,664					
Other Operating Revenue	4,609	4,609	4,609	4,609	4,609	Updated HECO-304 (Update, T-3, Att. 4, p. 1
Gain on Sale of Land	615	615	615	615	615	
TOTAL OPERATING REVENUES	1,966,888	5,224	5,224	5,224	5,224	
Fuel	816,654	816,654	816,654	816,654		ECAC Recovery - amount in base rates
Purchased Power	477,055	477,055	477,055	477,055		ECAC Recovery - amount in base rates
Production	82,423					
Transmission	13,930					
Distribution	30,515					
Customer Accounts	16,297					
Allowance for Uncoll. Accounts	1,411					
Customer Service	6,997					
Administration & General	77,863					
	na					
	na					
	na					
	na	14,076	14,076	14,076		Nominal Tab, Attachment 1
	na	5,022	5,022	5,022		Nominal Tab, Attachment 1
A&G Total Nominal Amounts		19,098	19,098	19,098		
Operation and Maintenance/Total Nominal Amounts	1,523,145	1,312,807	1,312,807	1,312,807		

Hawaiian Electric Company, Inc.

CIP (Full Cost w/o Wind Studies & Sales Red) at Curr Eff Rates
SUPPORT WORKSHEET

		2009	2010	2011
REVENUE TAX				
Public Service Tax				
Electric Sales Revenues		1,861,751	1,971,687.2	1,974,088.8
Other Operating Revenues		4,487	4,609.0	4,609.0
Less: Bad Debt Expense		(1,339)	(1,423.1)	(1,427.1)
Operating Revenues subject to PSC Tax		1,864,899	1,974,873	1,977,271
Public Service Tax Rate	x	5.885%	5.885%	5.885%
Total PSC Tax		109,749	116,221	116,362
PUC Fees				
Electric Sales Revenues		1,861,751	1,971,687.2	1,974,088.8
Other Operating Revenues		4,487	4,609.0	4,609.0
Less: Bad Debt Expense		(1,339)	(1,423.1)	(1,427.1)
Operating Revenues subject to PSC Tax		1,864,899	1,974,873	1,977,271
PUC Tax Rate	x	0.500%	0.500%	0.500%
Total PUC Tax		9,324	9,874	9,886
Franchise Tax				
Electric Sales Revenues		1,861,751	1,971,687.2	1,974,088.8
Less: Bad Debt Expense		(1,339)	(1,423:1)	(1,427.1)
		1,860,412	1,970,264	1,972,662
Franchise Tax Rate	x	2.500%	2.500%	2.500%
Total Franchise Tax		46,510	49,257	49,317
TOTAL REVENUE TAX		165,584	175,352	175,565

Maui Electric Company, Limited (MECO)

Rate Base Forecast Only
Rate Case -2007 Test Year - Probable Entitlement
Estimated 2006 Rate Case Average

Capitalization

	A	B	C	D
	Amount in Thousands	Percent of Total	Earnings Reqmts	Weighted Earnings Reqmts (B) x (C)
Short-Term Debt	4,750	1.27	5.00%	0.063%
Revenue Bond	150,585	40.15	6.11%	2.453%
Hybrid Securities	9,192	2.45	7.47%	0.183%
Preferred Stock	4,693	1.25	8.34%	0.104%
Common Equity	205,882	54.89	10.70%	5.873%
Total	375,102	100.00		
Estimated Composite Cost of Capital				8.676%
			or	8.68%

Hawaii Electric Light Company, Inc. (HELCO)

Rate Base Forecast Based on Regression Estimate Only
Rate Case -2006 Test Year - Settlement Results of Operatic
Estimated 2006 Rate Case Average

	A	B	C	D
	Capitalization			
	Amount in Thousands	Percent of Total	Earnings Reqmts	Weighted Earnings Reqmts (B) x (C)
Short-Term Debt	49,550	13.24	5.00%	0.662%
Revenue Bond	117,408	31.37	5.92%	1.857%
Hybrid Securities	9,152	2.45	7.50%	0.183%
Preferred Stock	6,563	1.75	8.37%	0.147%
Common Equity	191,544	51.19	10.70%	5.477%
Total	374,217	100.00		
Estimated Composite Cost of Capital				8.326%
			or	8.33%